U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-256 321

Proceedings of the Stationary Source Combustion Symposium. Volume II Fuels & Process Research & Development

Industrial Environmental Research Lab.

June 1976

KEEP UP TO DATE

Between the time you ordered this report—which is only one of the hundreds of thousands in the NTIS information collection available to you—and the time you are reading this message, several *new* reports relevant to your interests probably have entered the collection.

Subscribe to the **Weekly Government Abstracts** series that will bring you summaries of new reports *as soon as they are received by NTIS* from the originators of the research. The WGA's are an NTIS weekly newsletter service covering the most recent research findings in 25 areas of industrial, technological, and sociological interest—invaluable information for executives and professionals who must keep up to date.

The executive and professional information service provided by NTIS in the **Weekly Government Abstracts** newsletters will give you thorough and comprehensive coverage of government-conducted or sponsored research activities. And you'll get this important information within two weeks of the time it's released by originating agencies.

WGA newsletters are computer produced and electronically photocomposed to slash the time gap between the release of a report and its availability. You can learn about technical innovations immediately—and use them in the most meaningful and productive ways possible for your organization. Please request NTIS-PR-205/PCW for more information.

The weekly newsletter series will keep you current. But *learn what you have missed in the past* by ordering a computer **NTISearch** of all the research reports in your area of interest, dating as far back as 1964, if you wish. Please request NTIS-PR-186/PCN for more information.

WRITE: Managing Editor
5285 Port Royal Road
Springfield, VA 22161

Keep Up To Date With SRIM

SRIM (Selected Research in Microfiche) provides you with regular, automatic distribution of the complete texts of NTIS research reports *only* in the subject areas you select. SRIM covers almost all Government research reports by subject area and/or the originating Federal or local government agency. You may subscribe by any category or subcategory of our WGA **(Weekly Government Abstracts)** or **Government Reports Announcements and Index** categories, or to the reports issued by a particular agency such as the Department of Defense, Federal Energy Administration, or Environmental Protection Agency. Other options that will give you greater selectivity are available on request.

The cost of SRIM service is only 45¢ domestic (60¢ foreign) for each complete microfiched report. Your SRIM service begins as soon as your order is received and processed and you will receive biweekly shipments thereafter. If you wish, your service will be backdated to furnish you microfiche of reports issued earlier.

Because of contractual arrangements with several Special Technology Groups, not all NTIS reports are distributed in the SRIM program. You will receive a notice in your microfiche shipments identifying the exceptionally priced reports not available through SRIM.

A deposit account with NTIS is required before this service can be initiated. If you have specific questions concerning this service, please call (703) 451-1558, or write NTIS, attention SRIM Product Manager.

This information product distributed by

NTIS U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161

237147

PB 256 321

EPA-600/2-76-150b
June 1976

Environmental Protection Technology Series

UNITED STATES · ENVIRONMENTAL PROTECTION AGENCY ·

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into five series. These five broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The five series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies

This report has been assigned to the ENVIRONMENTAL PROTECTION TECHNOLOGY series. This series describes research performed to develop and demonstrate instrumentation, equipment, and methodology to repair or prevent environmental degradation from point and non-point sources of pollution. This work provides the new or improved technology required for the control and treatment of pollution sources to meet environmental quality standards.

EPA REVIEW NOTICE

This report has been reviewed by the U.S. Environmental Protection Agency, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policy of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/2-76-152b

2.

3. RECIPIENT'S ACCESSION NO.

4. TITLE AND SUBTITLE Proceedings of the Stationary Source Combustion Symposium; Volume II--Fuels and Process Research and Development

5. REPORT DATE June 1976

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S) Miscellaneous

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS NA

10. PROGRAM ELEMENT NO. 1AB014; ROAP 21BCC

11. CONTRACT/GRANT NO. NA (In-house)

12. SPONSORING AGENCY NAME AND ADDRESS
EPA, Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED Proceedings; 9/24-26/75

14. SPONSORING AGENCY CODE EPA-ORD

15. SUPPLEMENTARY NOTES Symposium Chairman J.S. Bowen, Vice-Chairman R.E. Hall, Mail Drop 65, Ext. 2470/2477.

16. ABSTRACT The proceedings document the 37 presentations made during the Stationary Source Combustion Symposium held in Atlanta, Ga., September 24-26, 1975. Sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory--RTP, the symposium dealt with subjects related both to developing improved combustion technology for the reduction of air pollutant emissions from stationary sources, and to improving equipment efficiency. The symposium was divided into four parts and the proceedings were issued in three volumes: Volume I--Fundamental Research, Volume II--Fuels and Process Research and Development, and Volume III--Field Testing and Surveys. The symposium was intended to provide contractor, industrial, and Government representatives with the latest information on EPA in-house and contract combustion research projects related to pollution control, with emphasis on reducing nitrogen oxides.

PRICES SUBJECT TO CHANGE

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution, Combustion, Field Tests	Air Pollution Control	13B 21B 14B
Combustion Control, Coal, Oils	Stationary Sources	21D 11H
Natural Gas, Nitrogen Oxides, Carbon	Combustion Modification	07B
Carbon Monoxide, Hydrocarbons, Boilers	Unburned Hydrocarbons	07C 13A
Pulverized Fuels, Fossil Fuels, Utilities	Fundamental Research	
Gas Turbines, Efficiency	Fuel Nitrogen	13G 14A
	Burner Tests	

18. DISTRIBUTION STATEMENT Unlimited

19. SECURITY CLASS *(This Report)* Unclassified

20. SECURITY CLASS *(This page)* Unclassified

21. NO. OF PAGES 424

22. PRICE $11.00 - 2.25

EPA Form 2220-1 (9-73)

EPA-600/2-76-152b
June 1976

PROCEEDINGS OF THE
STATIONARY SOURCE COMBUSTION SYMPOSIUM
VOLUME II--FUELS AND PROCESS RESEARCH AND DEVELOPMENT

Joshua S. Bowen, Chairman
Robert E. Hall, Vice-Chairman

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

ROAP No. 21BCC
Program Element No. 1AB014

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

PREFACE

The Stationary Source Combustion Symposium was held on September 24-26, 1975, at the Fairmont Colony Square Hotel in Atlanta, Georgia. The symposium was sponsored by the Combustion Research Branch of E.P.A.'s Industrial Environmental Research Laboratory (IERL). The Combustion Research Branch has been involved in developing improved combustion technology for the reduction of air pollutant emissions from stationary sources, and improving equipment efficiency.

Dr. Joshua S. Bowen, Chief, Combustion Research Branch, was Symposium Chairman; Robert E. Hall, Research Mechanical Engineer, Combustion Research Branch, was Symposium Vice Chairman and Project Officer. The Welcome Address was delivered by Dr. John K. Burchard, Director of the Industrial Environmental Research Laboratory. Frank Princiotta, Acting Director of the Energy Processes Division of E.P.A.'s Office of Energy, Minerals, and Industry, was the Keynote Speaker.

The Symposium consisted of four Sessions:

Session I: Fundamental Research

Co-chairmen: Dr. Joshua A. Bowen

W. Steven Lanier, Research Mechanical Engineer, E.P.A., IERL, Combustion Research Branch

Session II: Fuels Research and Development

Chairman: G. Blair Martin, Chemical Engineer, E.P.A., IERL,
Combustion Research Branch

Session III: Process Research and Development

Chairman: David G. Lachapelle, Research Chemical Engineer,
E.P.A., IERL, Combustion Research Branch

Session IV: Field Testing and Surveys

Co-chairmen: Robert E. Hall
John H. Wasser, Research Chemical Engineer, E.P.A.,
Combustion Research Branch

These Session Chairmen have reviewed the transcriptions of the question and answer sessions, and, in addition, have worked with authors to clarify and revise presentations, where appropriate, and to make them clear and meaningful for these printed proceedings.

We are grateful for the cooperation of Marjorie Maws, Project Leader; Anita Lord, Symposium Administrator; and Margaret Kilburn, Program Director, of Arthur D. Little, Inc., who coordinated the symposium for E.P.A.

CONTENTS

Preface iii

Welcome Address - J.K. Burchard I-1

Keynote Address - F.T. Princiotta I-3

SESSION I - FUNDAMENTAL RESEARCH

Formation of Soot and Polycyclic Aromatic Hydrocarbons (PCAH) in Combustion Systems I-18

J.D. Bittner, G.P. Prado, J.B. Howard, R.A. Hites

Questions and Answers I-32

Effects of Fuel Sulfur on Nitrogen Oxide Emissions. I-35

J.O.L. Wendt, J.M. Ekmann

Questions and Answers I-88

Two-Dimensional Combustor Modeling I-91

R.C. Buggeln, H. McDonald

Questions and Answers . . . . (n/a)

Effects of Interaction Between Fluid Dynamics and Chemistry on Pollutant Formation in Combustion I-109

C.T. Bowman, L.S. Cohen, L.J. Spadaccini, F.K. Owen

Questions and Answers I-119

Fate of Coal Nitrogen During Pyrolysis and Oxidation I-125

J.H. Pohl, A.F. Sarofim

Questions and Answers I-147

A Detailed Approach to the Chemistry of Methane/Air Combustion: Critical Survey of Rates and Applications I-153

V.S. Engleman

Questions and Answers I-182

Chemical Reactions in the Conversion of Fuel Nitrogen to NOx I-185

A.E. Axworthy, G.R. Schneider, V.H. Dayan

Questions and Answers I-211

Prediction of Premixed Laminar Flat Flame Kinetics, Including the Effects of Diffusion I-217

R.M. Kendall, J.T. Kelly, W.S. Lanier

Questions and Answers I-266

Estimation of Rate Constants I-267

S.W. Benson, R. Shaw, R.W. Woolfolk

Questions and Answers . . . . (n/a)

Production of Oxides of Nitrogen in Interacting Flames I-291

C. England

Questions and Answers I-316

Concurrent Panel Discussions:

1. Combustion Chemistry and Modeling: An Overview

A.F. Sarofim - Combustion Chemistry and Modeling I-325

Questions and Answers I-345

T.J. Tyson - The Mathematical Modeling of Combustion Devices I-347

Questions and Answers I-410

2. Federal, Regional, State, and Local Air Pollution Regulations: An Overview

S. Cuffe - Federal I-413
G.T. Helms - Regional I-429
R.H. Collum - State I-443
H.W. Poston - Local I-447

SESSION II - FUELS RESEARCH AND DEVELOPMENT

Assessment of Combustion and Emission Characteristics of Methanol and Other Alternate Fuels II-3

G.B. Martin

Questions and Answers II-30

Burner Design Criteria for Control of Pollutant Emissions from Natural Gas Flames II-31

D.F. Shoffstall

Questions and Answers . . . . (n/a)

Integrated Low Emission Residential Furnace II-81

L.P. Combs, W.H. Nurick, A.S. Okuda

Questions and Answers II-101

The Control of Pollutant Emissions from Oil Fired Package Boilers II-109

M.P. Heap, T.J. Tyson, E. Cichanowicz, R.E. McMillan, F.D. Zoldak

Questions and Answers II-160

Pilot Scale Investigation of Catalytic Combustion Concepts for Industrial and Residential Applications II-163

J.P. Kesselring, R.M. Kendall, C.B. Moyer, G.B. Martin

Questions and Answers II-196

The Optimization of Burner Design Parameters to Reduce NOx Formation in Pulverized Coal and Heavy Oil Flames II-197

M.P. Heap, T.J. Tyson, G.P. Carver, G.B. Martin, T.M. Lowes

Questions and Answers II-239

Pilot Scale Investigation of Combustion Modification Techniques for NOx Control in Industrial and Utility Boilers II-241

R.E. Brown, C.B. Moyer, H.B. Mason, D.G. Lachapelle

Questions and Answers II-267

SESSION III - PROCESS RESEARCH AND DEVELOPMENT

Overfire Air as an NOx Control Technique for Tangential Coal-Fired Boilers III-3

A.P. Selker

Questions and Answers III-26

Control of NOx Formation in Wall Coal-Fired Boilers III-31

G.A. Hollinden, J.R. Crooks, N.D. Moore, R.L. Zielke, C. Gottschalk

Questions and Answers III-77

The Effect of Additives in Reducing Particulate Emissions from Residual Oil Combustion III-83

R.D. Giammar, H.H. Krause, A.E. Weller, D.W. Locklin

Questions and Answers III-115

System Design for Power Generation from Low Btu Gas Boilers III-119

M.P. Heap, T.J. Tyson, N.D. Brown

Questions and Answers . . . . (n/a)

SESSION IV - FIELD TESTING AND SURVEYS

The Effect of Combustion Modification on Pollutants and Equipment Performance of Power Generation Equipment IV-3

A.R. Crawford, E.H. Manny, M.W. Gregory, W. Bartok

Questions and Answers IV-109

Analysis of Gas-, Oil-, and Coal-Fired Utility Boiler Test Data IV-115

O.W. Dykema, R.E. Hall

Questions and Answers IV-161

Influence of Combustion Modifications on Pollutant Emissions from Industrial Boilers IV-163

G.A. Cato, L.J. Muzio, R.E. Hall

Questions and Answers IV-219

Emission Characteristics of Small Gas Turbine Engines IV-227

J.H. Wasser

Questions and Answers IV-252

Systems Evaluation of the Use of Low-Sulfur Western Coal in Existing Small- and Intermediate-Sized Boilers IV-255

K.L. Maloney

Questions and Answers IV-316

A Survey of Emissions Control and Combustion Equipment Data in Industrial Process Heating IV-321

P.A. Ketels, J.D. Nesbitt, D.R. Shoffstall, M.E. Fejer

Questions and Answers . . . . (n/a)

POM and Particulate Emissions from Small Commercial Stoker-Fired Boilers IV-411

R.D. Giammar, R.B. Engdahl, R.E. Barrett

Questions and Answers IV-439

Concluding Remarks - J.S. Bowen IV-441

Appendix

List of Speakers A-1

List of Participants

Alphabetically by Name A-2
Alphabetically by Organization A-6

SESSION II

FUELS RESEARCH AND DEVELOPMENT

G. B. Martin, Chairman

ASSESSMENT OF COMBUSTION AND EMISSION CHARACTERISTICS OF METHANOL AND OTHER ALTERNATE FUELS

by

G. Blair Martin
Combustion Research Branch
Energy Assessment and Control Division
Industrial Environmental Research Laboratory
U. S. Environmental Protection Agency

Research Triangle Park, North Carolina

Preceding page blank

INTRODUCTION

The Combustion Research Branch (CRB) of the EPA's Industrial Environmental Research Laboratory at Research Triangle Park, N. C., has the responsibility for carrying out a combustion modification R&D program directed toward control of nitrogen oxides and other pollutants from stationary combustion sources. In addition to pollutant emission control it appears that the technology can also lead to equal or improved efficiency of energy utilization. The majority of the R&D is carried out under EPA contracts initiated and directed by CRB and performed by private organizations. However, CRB also maintains an in-house research program in a number of areas. This in-house activity provides direct project officer expertise in combustion research and provides the capability for initial evaluation of potential control techniques or promising novel concepts applicable to combustion systems. The results of many of these studies are well documented.

For several years, one in-house project has been devoted to establishing the combustion and emission characteristics of alternate fuels (e.g., alcohol fuels, low Btu gas), an area that is now receiving increased emphasis in the United States. The goals of this project have been threefold: first, to determine the potential advantages or problems related to the combustion of these fuels; second, to obtain some understanding of the important factors governing the combustion and emission characteristics and of potential control techniques; and, finally, to define necessary R&D for application of these fuels in practical combustion systems. The supply of alternate fuels available for evaluation has been quite limited to date; however, one class, the alcohol fuels, is quite readily simulated with chemical grade pure alcohols. Therefore the combustion and emission characteristics of methanol and methanol-isopropanol mixtures have received the primary emphasis to date.

The purpose of this paper is to summarize the results of the alcohol fuel testing and to describe briefly the future direction of the project.

ALCOHOL FUELS

This section provides a short background on sources of alcohol fuels, a summary of the available information on combustion and emission characteristics of alcohol fuels as compared to conventional fuels, and information on a recent series of tests on emulsions of methanol and distillate oil.

Background

The bulk of the methanol produced in the United States today is synthesized from natural gas for end use as a chemical. There is obviously little benefit to be derived from using this type of alcohol as a fuel; however, other approaches may be attractive. It has been shown that it is feasible to produce methanol from a synthesis gas generated by coal gasification.(1) In addition, Duhl(2) has proposed a Methyl Fuel, consisting of about 90% methanol and the balance higher alcohols, as a more economical and efficient synthesis process for a variety of starting materials. Finally, biological synthesis from waste materials may be possible. The ultimate place of alcohols in the alternate fuel picture will depend on a number of factors, including: fuel cost, overall energy efficiency relative to other fuels, and environmental considerations of production and use. It would appear that alcohols might be in competition with other clean high Btu fuels (e.g., Synthetic Natural Gas) to supplement or replace dwindling supplies of natural gas and light fuel oils in combustion equipment requiring clean fuels.

Although there is a large body of information on the use of alcohol fuels in automobiles, the combustion characteristics of these fuels in continuous combustion devices of the type used in stationary sources have received very little attention. Duhl(2) published very limited data for a small boiler which showed some promising results; however, little detail was given. This paucity of detailed data led to this study.

Summary of Combustion Results

The studies were directed toward defining the combustion and emission characteristics of alcohol fuels and understanding the critical phenomena involved. Most of the results have been reported in detail elsewhere(3) and are summarized in this section. In addition, the experiments were recently extended to examine the use of alcohols as a supplement to conventional fuels, similar to the methanol-gasoline blends being considered for automotive use. The approach taken was to study emulsions of distillate oil and methanol.

Experimental Equipment

The experimental equipment was also described in detail in reference 3, and the key features are summarized here. The basic combustion chamber is a refractory lined cylindrical chamber 0.267 meters in diameter and 1.22 meters long. The nominal heat input was maintained constant at 88,000 watts for all fuels and the combustion air was 115% of theoretical for all cases. The burner is a movable block swirl burner of well known design(4) and is capable of controlling the ratio of axial to tangential momentum of the combustion air over a wide range. Liquid fuels were atomized through high pressure nozzles and propane was introduced through a radial hole injector. Flue gas recirculation was simulated by withdrawing cooled product gas from the stack and mixing it with the combustion air. Emulsions were prepared with a Total device on loan to our laboratory.

Experimental Results

The initial activity in evaluation of an alternate fuel is to compare its combustion and emission performance to conventional fuels. The baseline fuels were a distillate fuel oil and propane, representing both liquid and gaseous conventional fuels. The alcohols were methanol, isopropanol and a mixture containing 50% of each, thereby allowing an assessment of the effect of the presence of higher alcohols on the methanol combustion. Figure 1 shows a comparision of NO emissions as a function of the swirl block position (SBP), where the tangential momentum of the combustion air increases as the swirl block position increases. The salient features of this figure are as follows:

1) The NO emission for distillate oil shows a distinct peak at SBP of 4.

2) The NO emissions for propane and the alcohol fuels decrease continuously as the SBP is increased from 2 to 8.

3) The alcohol fuels have lower NO emissions than either of the conventional fuels.

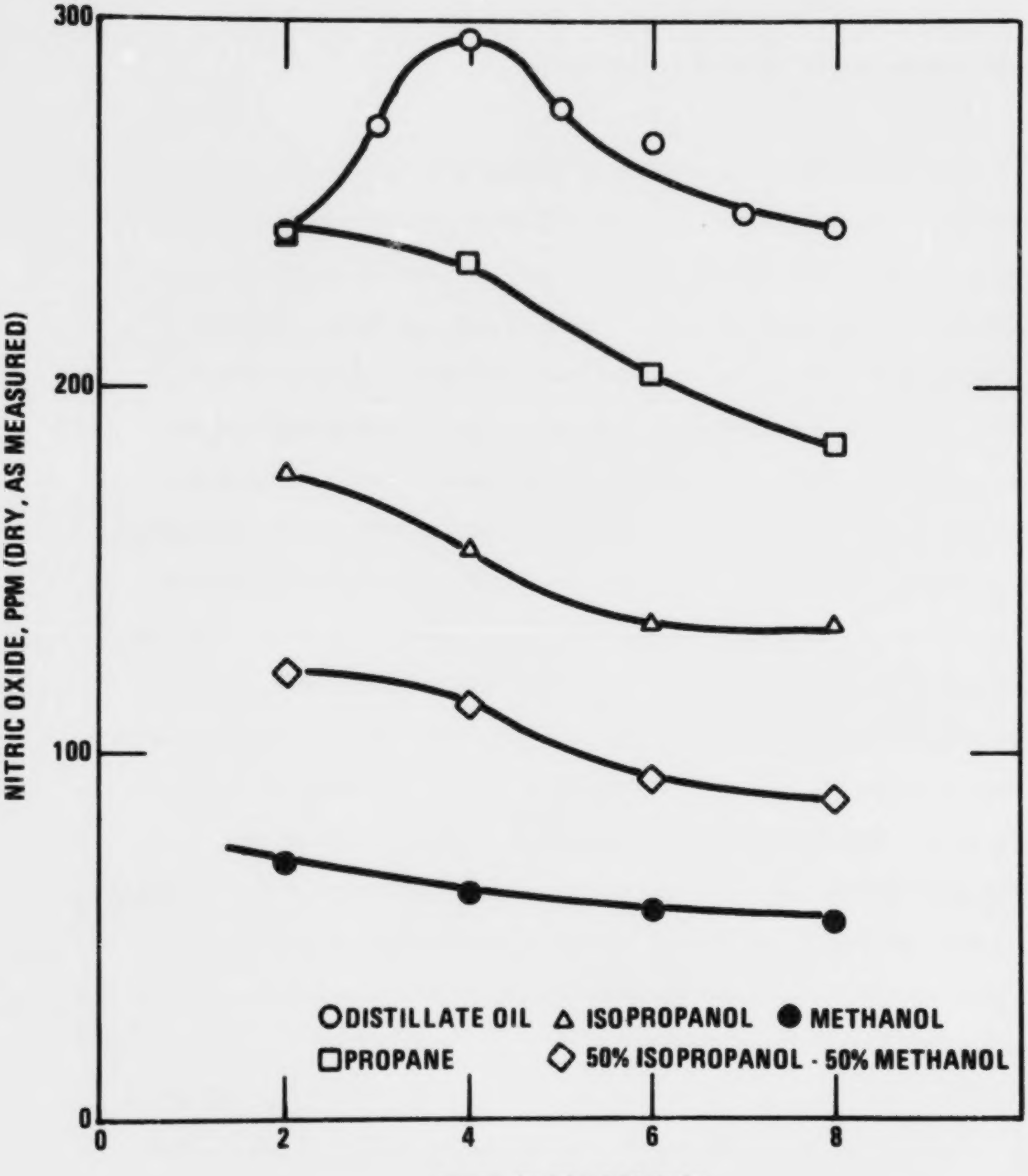


FIGURE 1. COMPARISON OF BASELINE NITRIC OXIDE EMISSIONS FOR VARIOUS FUELS AS A FUNCTION OF SWIRL PARAMETER.

4) The NO emissions of the alcohol fuels decrease as the percentage of isopropanol decreases.

It is interesting that, although the alcohol fuels are liquids, their emission characteristics are more like those of gaseous propane than of the liquid distillate oil. This is probably related to vaporization of the low boiling alcohols early in the combustion zone as indicated by observation of the flame. The spray is only visible for about 2 to 5 cm and the flame has a blue to nonluminous appearance which is quite similar to propane flames. The low NO for the alcohols and the trend as a function of alcohol type may be postulated to result from the partially oxidized nature of the alcohol having the effect of diluent addition to the flame zone. Viewed in this way methanol can be viewed as a $CH_2 \cdot H_2O$ fuel and compared to a $CH_{1.8}$ representation of the distillate oil. The methanol therefore requires nearly twice the fuel mass to supply the same heat input to the furnace. For convenience, the term "bound water" will be used for the preoxidized part of the alcohols. The bound water is 54, 43 and 30 mass percent for methanol, the 50/50 mixture and isopropanol, respectively. Increasing the diluent mass would reduce flame temperature and therefore thermal NO.

To examine the validity of the postulated effect of bound water, a series of tests on water-in-oil emulsions was run and the results are plotted in Figure 2 for an SBP of 4. The line was drawn for the water-in-oil emulsions and the alcohol results plotted for comparison. For any given alcohol fuel the NO emissions compare quite well to the emulsion results of the same water content.

To allow comparision of the alcohol results with another dilution technique, the effect of the flue gas recirculation was examined and the results are presented in Figure 3. This shows that a further reduction of NO emissions is possible for all of the fuels with about 85% reduction possible at 25% FGR.

The effect of any diluent on thermal NO is based on a reduction of peak flame temperatures and, thereby, a reduction in the rates of formation. To allow a comparison of all the techniques on a common basis, the NO emissions are plotted versus theoretical flame temperature as shown in Figure 4. Note that the temperature is calculated based on fully equilibrated products at the overall stoichiometry of the system for adiabatic conditions. Since the combustion system is hot wall (about 1400°C) and designed for minimum heat loss, the assumption of adiabatic conditions may be reasonably good. The assumption that the reaction occurs at the overall stoichiometry is more open to question for the diffusion flame system and may aid in explaining the differences seen in the figure. The most important factor may be the differences in fuel vaporization and atomization

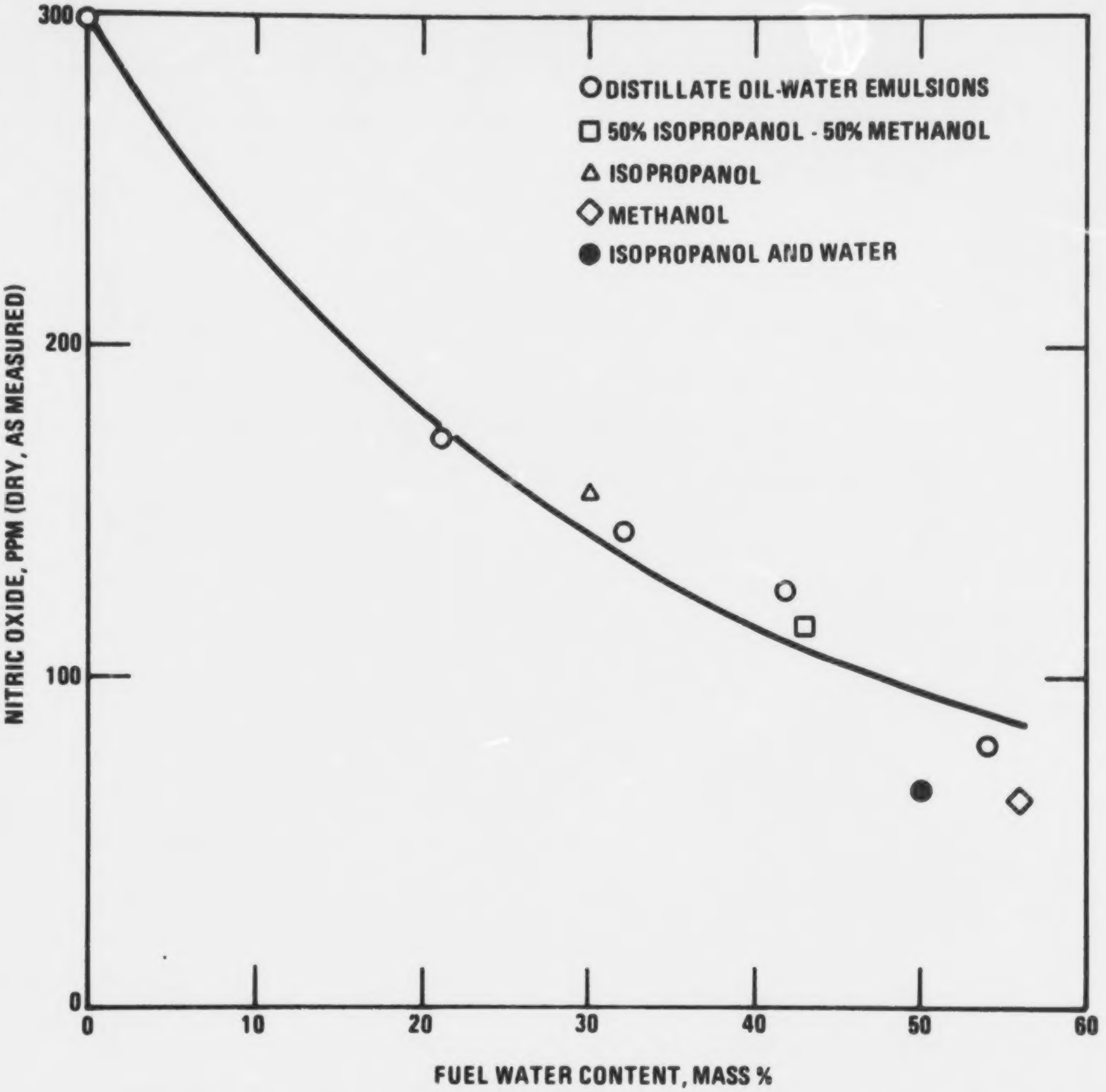


FIGURE 2. COMPARISON OF NITRIC OXIDE EMISSIONS FOR VARIOUS FUELS AS A FUNCTION OF WATER CONTENT.

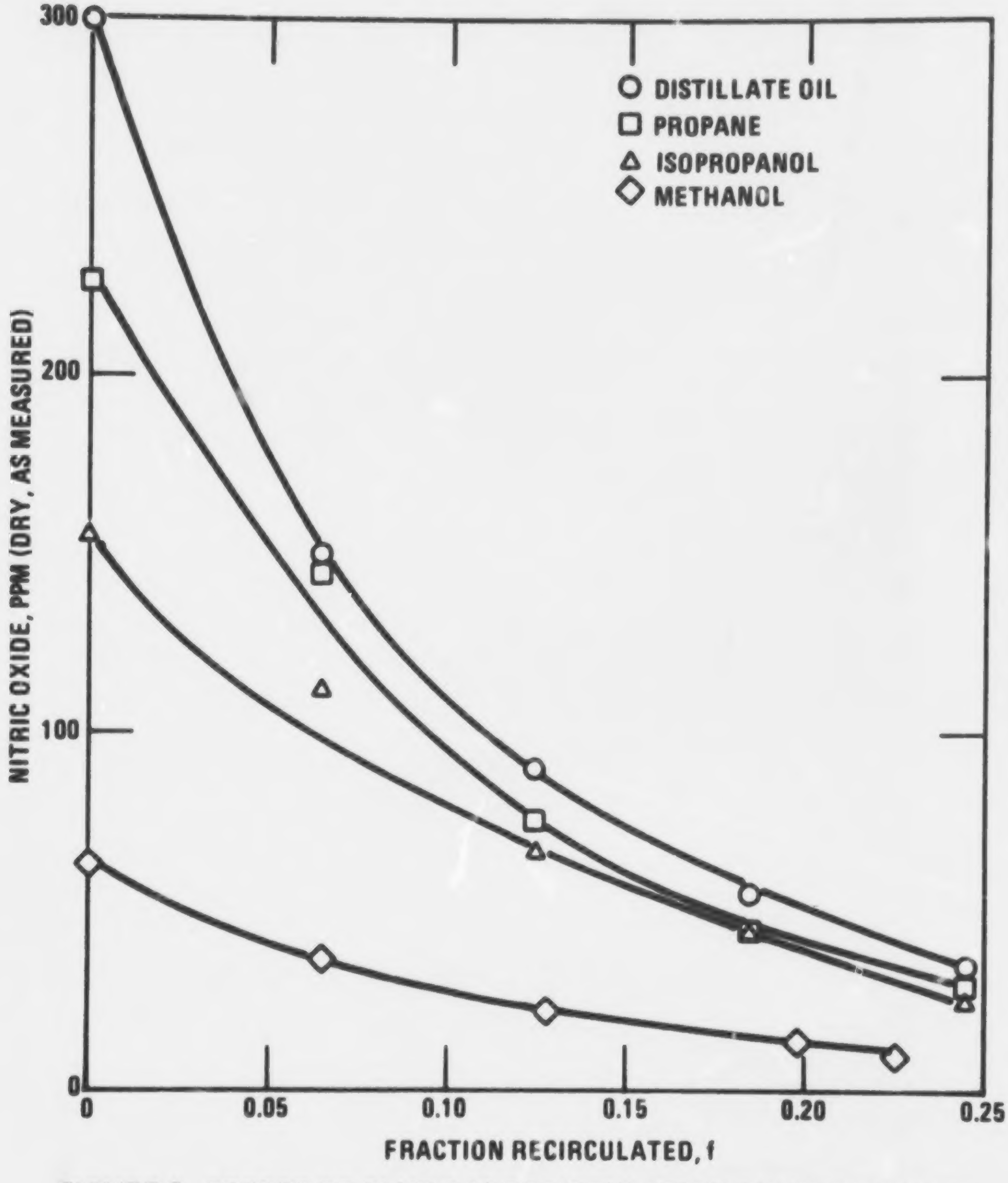


FIGURE 3. EFFECT OF FLUE GAS RECIRCULATION ON NITRIC OXIDE EMISSIONS FOR VARIOUS FUELS.

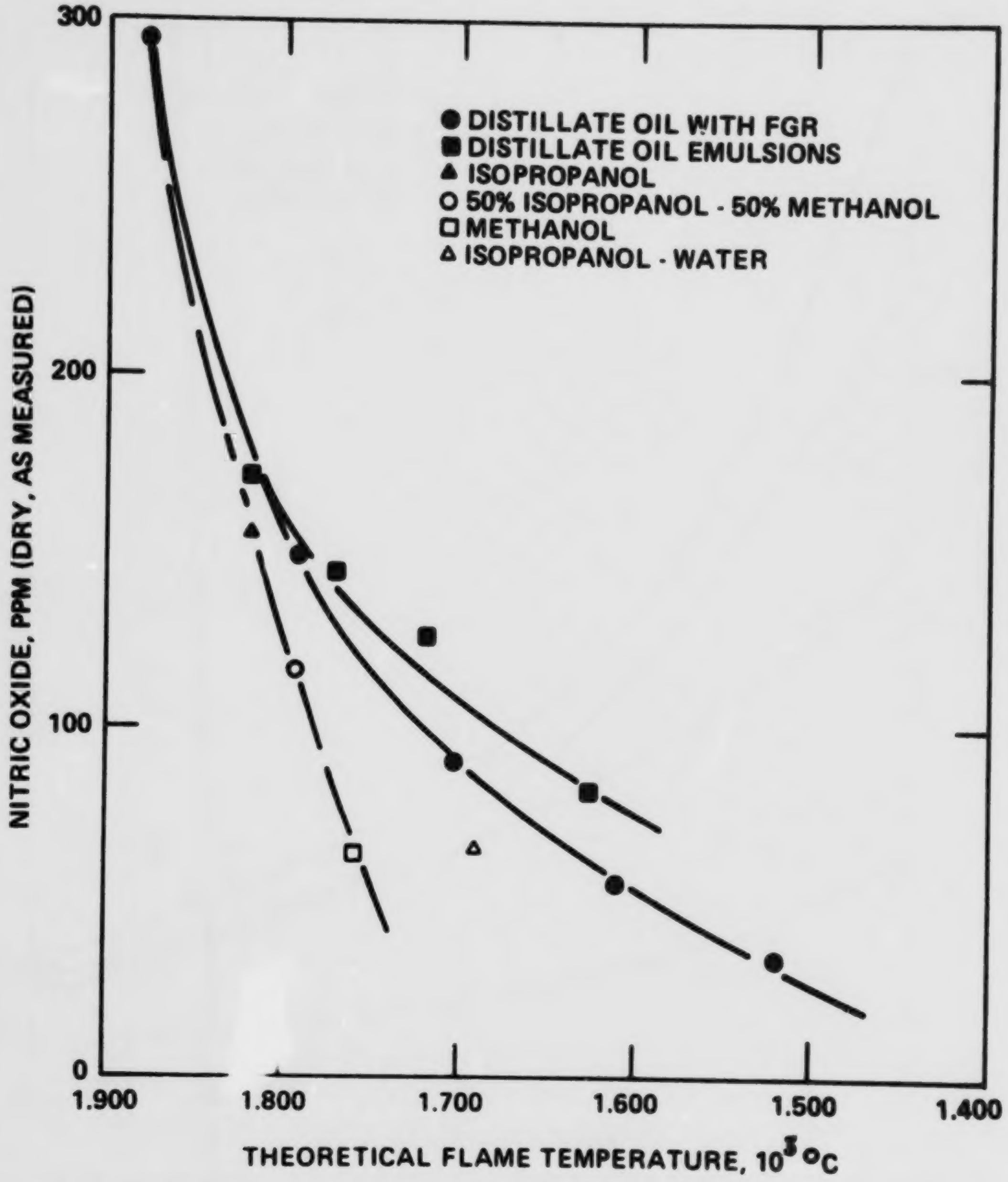


FIGURE 4. COMPARISON OF NITRIC OXIDE EMISSION REDUCTION AS A FUNCTION OF THEORETICAL FLAME TEMPERATURE FOR VARIOUS DILUENT ADDITION TECHNIQUES.

characteristics coupled with the fuel-air mixing characteristics of the system. An explanation may be summarized as follows:

1) For the water-in-oil emulsion, the water droplets are believed to shatter causing a secondary atomization of the oil. It is also possible that at the higher water levels the emulsions may tend to separate. In either case the oil may burn in an environment where the diluent effect of the water is less than that calculated and the actual flame temperature is higher.

2) For the flue gas recirculation the diluent is uniformly mixed with the combustion air and should have the same effect on the flame temperature no matter where the fuel burns; however, the fuel reactions still may occur at conditions closer to stoichiometric than the overall mixture which would have the effect of increasing peak temperatures locally.

3) For the alcohols, not only is the "diluent" intimately bound in the fuel molecule, but the early vaporization may allow more rapid mixing with the combustion air. This would most closely approximate the basis on which the flame temperature calculations were made.

4) Finally the alcohol fuels have high latent heats of vaporization which may result in a significant local heat extraction

and an associated NO reduction.

The final series of experiments examined the effects of alcohol and distillate oil emulsions on NO emissions. The total heat input to the furnace was kept at a constant value and the percent of heat input in the form of methanol was increased from zero to 100%. The average results of three series of tests are shown in Figure 5. The first 25% methanol reduced the NO emissions by about 50% relative to distillate oil alone. To allow a comparison on a common basis the "bound water" in the methanol was calculated as a water content for the total mixture and plotted along with the water in oil emulsion in Figure 6. For a given water content in the fuel mass the methanol-oil emulsions give consistently lower NO emission than do the water-oil emulsions. This may be attributable to a number of factors including:

1) The methanol has a lower boiling point than does water and may provide a more efficient secondary atomization effect. This would promote better mixing and a greater effect of the diluent on the combustion temperature.

2) Not only does the methanol have a higher heat of vaporization per mass than the water, but also there is a larger mass to be vaporized for a given "water" content, resulting in a more significant effect on peak flame temperature.

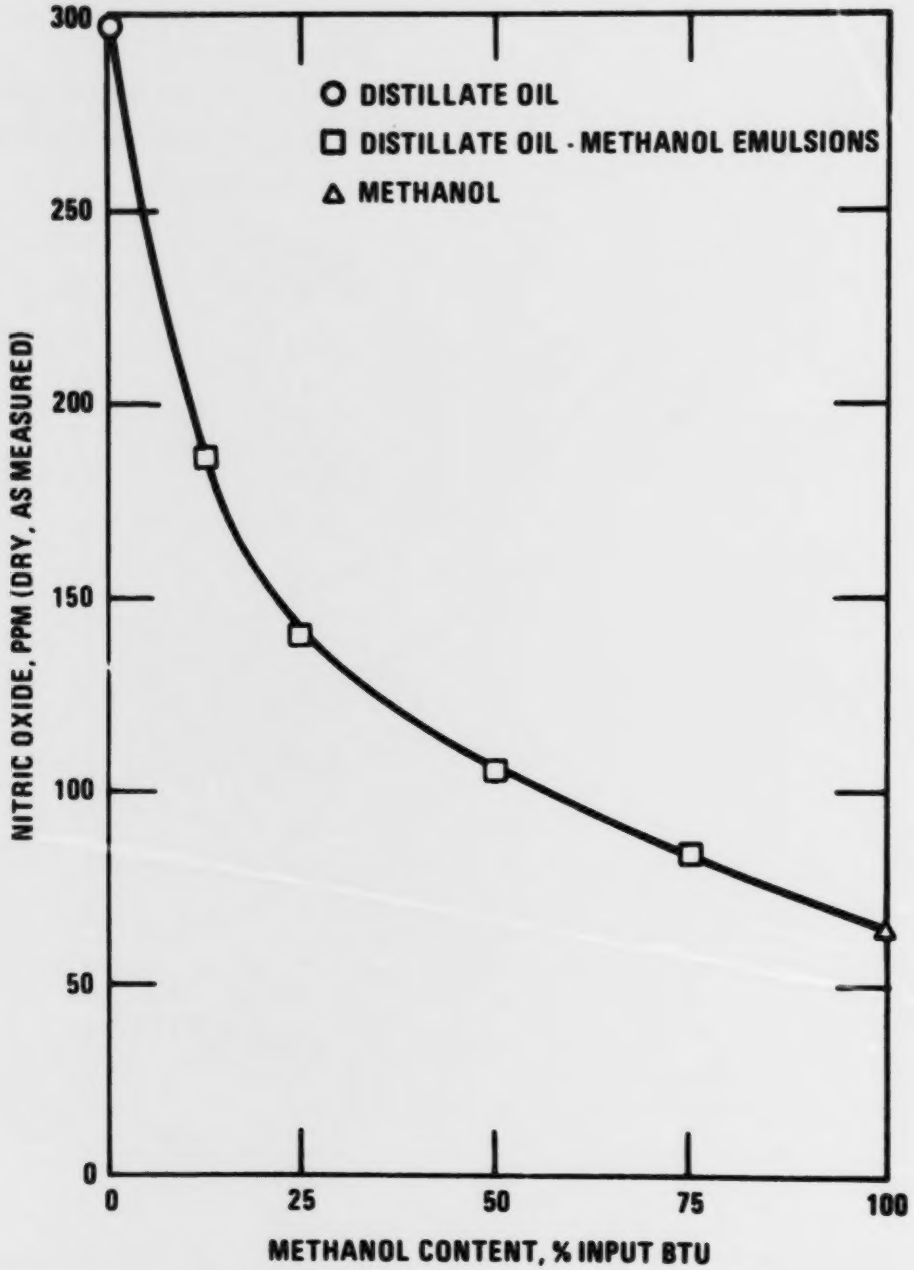


FIGURE 5. NITRIC OXIDE EMISSIONS FOR METHANOL - DISTILLATE OIL EMULSIONS AS A FUNCTION OF METHANOL HEAT INPUT.

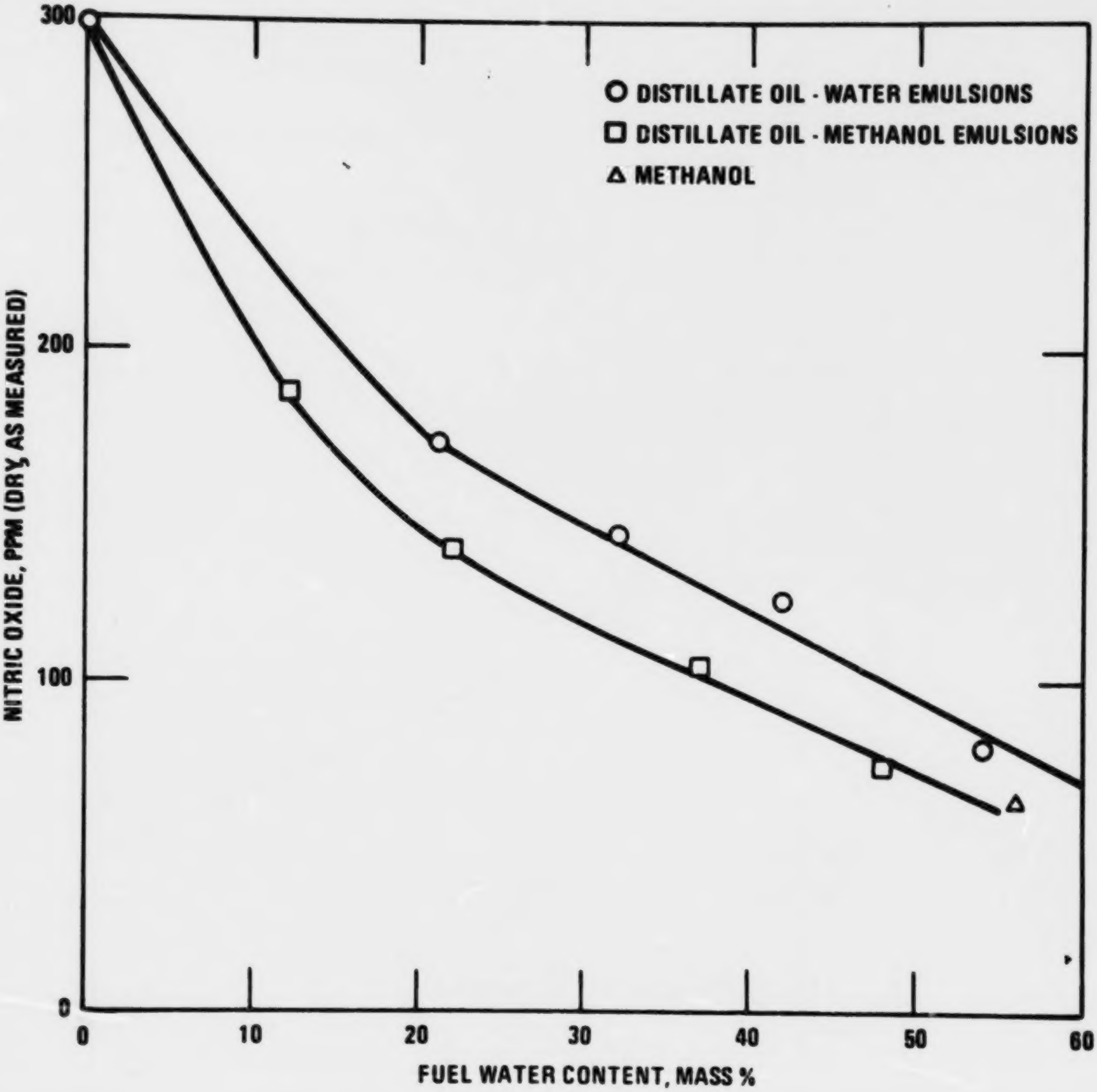


FIGURE 6. COMPARISON OF NITRIC OXIDE EMISSIONS FOR WATER AND METHANOL WITH DISTILLATE OIL AS A FUNCTION OF WATER CONTENT.

It should be stated that, although the explanations offered here (based on temperature effects on thermal NO) appear to explain most of the observed phenomena, some anomalies still exist in the methanol data. At this time it is not possible to assess the effect of the methanol on flame chemistry. It is possible that the methanol reaction scheme may reduce concentrations of certain radical species and thereby reduce non-Zeldovitch NO. This possibility will be explored in the laboratory by combustion of a mixture of 33% CO and 76% H_2 to simulate a decomposed methanol.

Conclusions

Based on the results presented here and other information contained in reference 3, the following conclusions can be drawn:

1) Alcohol fuels produce lower emissions of nitrogen oxides than distillate oil or propane.

2) The NO emissions of alcohol fuels increase as the percentage of higher alcohols increases.

3) The low NO emissions for alcohol fuels appear to function from the presence and level of oxygen in the fuel molecule, which can be viewed as a diluent carried in the fuel. The operative mechanism appears to be related to thermal effects of the fuel, latent heat of vaporization, and/or decreased flame temperature; however, chemical effects cannot be totally ruled out.

4) In the hot wall experimental system, NO levels similar to those for methanol (e.g., 65 ppm) could be attained for distillate oil and propane with flue gas recirculation and could be approached at 50% water for distillate oil emulsions.

5) Based on the calculations, the use of methanol and a

water-oil emulsion appears to impose a 6 to 7% increase in stack heat loss compared to distillate oil with flue gas recirculation; however, it is anticipated that there will be some compensating factors that can be designed into practical systems to minimize the losses, based on lower excess air operation as seen in the package boiler simulator.

6) The emissions of CO, UHC, and particulate from alcohol fuels were generally the same as, or less than, those for the conventional clean fuels tested (propane and distillate oil). Aldehydes do not appear to be a significant problem based on limited data generated under EPA contract 68-02-1498 with Ultrasystems, Inc.(3)

7) From a technical standpoint, methanol appears to be a satisfactory fuel for stationary combustion systems; however, the final commercial feasibility will probably depend more on cost and availability than on the ability to burn the fuel.

FUTURE PROGRAM

The future work in this area will be on other alternate fuels that appear to have some potential for application to stationary combustion sources. The fuels of interest and current plans of research direction are summarized below.

Background

In addition to the alcohol fuels there are a number of other fuels that may be derived from coal, oil shale or refuse at some time in the future. These possibilities cover the range of gaseous, liquid and solid fuels, with a number of candidates for each of these types.

Gaseous Fuels

The gaseous fuels of interest can be divided into the broad categories of Synthetic Natural Gas (SNG) and producer gas. The SNG is a high Btu fuel to replace or supplement natural gas in pipelines and the properties of the two types of SNG are compared to natural gas in Table 1. Unless some information develops to indicate a large divergence of combustion and/or emission characteristics of SNG from those of natural gas, the current technology for methane combustion should be adequate for emission control. The properties of low Btu gas vary widely depending on both the feed material and on the process used; the energy content can range from 4403 to 8806 KJ/M^3 as shown in Table 1. The combustion characteristics of these fuels are just beginning to be studied; however, several aspects already have come to light. First, due to the nature of the fuel, the adiabatic

TABLE 1. COMPARISON OF VARIOUS GASEOUS FUELS

Type of Fuel	Higher Heating Value KJ/M^3 (Dry)	Gas Composition, Mole %[c] CO	H_2	C_xH_y	Inerts[d]
Texarkana Natural Gas[a]	36,083	0.0	0.0	96.0	4.0
Cleveland Natural Gas[a]	42,200	0.0	0.0	98.7	1.3
Synthetic Natural Gas Koppers-Totzek[b]	35,896	0.08	2.5	94.2	3.2
Synthetic Natural Gas Lurgi[b]	36,586	0.0	0.8	96.8	2.4
Low Btu Gas-Lurgi[b]	6,717	13.9	19.6	5.5	61.0
Low Btu Gas-Winkler[b]	4,403	19.0	11.7	0.5	68.8
Low Btu Gas-Hygas[b]	8,806	13.6	16.8	9.1	60.5
Low Btu Gas-U-Gas[b]	5,597	17	11.6	4.1	67.3

a) Handbook of Chemical Engineering, John H. Perry--Editor, 3rd Edition.

b) "Clean Fuels from Coal Symposium Papers," Institute of Gas Technology, Sept. 10-14, 1973.

c) C_xH_y Represents CH_4 and C_2H_6

d) Inerts consist of CO_2, H_2O and N_2

flame temperature is lower than conventional fuels and thermal NO promises to be low. However, if the high temperature processes for H_2S removal are developed and the fuel gas is presented to the burner at 550 to 850°C, significant thermal NO may result. Second, the presence of significant amounts of ammonia appears to exist in the product gas at the gasifier exit for many processes. Unless this bound nitrogen is removed in the gas clean up sequence prior to combustion, significant fuel NO can result. Robson(5) states that 600 ppm of NH_3 can be present in the fuel gas following some low temperature H_2S removal processes, and projects 3800 ppm for some of the hot H_2S removal processes under development. This then identifies high temperature fuel gas and chemically bound nitrogen as two potential sources of NO that must be considered in low Btu gas combustion technology development.

Liquid Fuels

The liquid fuels of interest can be derived from either coal liquefaction or shale processing and some potential products are shown in Table 2. It can be noted that, while the sulfur content is relatively low (0.2 to 0.76%), the fuel nitrogen is quite high (0.68 to 1.77%) as compared to a residual oil produced from petroleum stock. While the hydrotreated COED oil shows that the heteroatom content can be reduced, this represents another processing step and extra cost for the finished fuel. If these fuels can be burned in the crude form and the emissions

TABLE 2. COMPARISON OF VARIOUS LIQUID FUELS

Fuel	Higher Heating Value KJ/KG	Ultimate Analysis, Weight %				
		C	H	N	S	O
Distillate Oil(a)	44,892	86.9	13.1	0.023	0.096	0.0
Residual Oil(a)	44,147	86.8	12.5	0.22	0.89	0.0
COED Crude(b)	--	83.0	8.4	1.1	0.35	7.15
COED(b) Hydrotreated	--	88.0	11.6	0.01	0.01	0.38
Synthoil(b)	39,077	89.6	7.6	0.9	0.31	1.6
H-Coal Crude(b)	--	--	9.5	0.68	0.19	--
H-Coal Low Sulfur	--	--	8.4	1.05	0.43	--
Toscoal Oil(b)	37,681	80.7	9.1	0.7	0.2	9.4
Shale Oil	43,496	84.6	11.7	1.77	0.76	--
Alcohol Fuel	22,278	37.5	12.5	0.0	0.0	50.0

(a) CRB in-house fuels

(b) "Clean Fuels from Coal Symposium Papers," Institute of Gas Technology, Sept. 10-14, 1973.

of NO_x and smoke effectively controlled by combustion technology, significant cost and/or overall energy efficiency savings may be realized. The thrust of the in-house research will be exploring the possible approaches to minimizing the emissions.

Planned Program

The near term emphasis in the in-house research project will be low Btu gases; liquid fuels will be included as suitable candidates become available.

Gas Generator

A catalytic partial oxidation reactor developed by the Jet Propulsion Laboratory for automotive use is being adapted as a gas generator to supply a variety of simulated low Btu gases. The reactor will accept a variety of hydrocarbons and reform these to yield a product fuel gas closely approximating the predicted equilibrium composition based on the input fuel to air stoichiometry. The reactor can be operated with about 40 to 70% of theoretical air. By changing the fuel type from methane to benzene and the input stoichiometry, the CO to H_2 ratio and the energy content of the product gas can be controlled over wide ranges. At design condition the reactor will produce approximately 88,000 watts of fuel gas at a temperature of 650 to 720°C. The product gas temperature will be controlled down to 120°C by additional heat exchange.

Research Areas

The program will address the two areas previously identified as requiring attention, fuel gas temperature and bound nitrogen, for several gas compositions. The gas compositions will strongly depend on the capability of the gas generator as delivered; however, the variables of interest are: 1) CO to H_2 volume ratio in the range of 0.5 to 2; and 2) energy content between 2980 and 7460 KJ/M^3. The composition of the gas will also be altered by the addition of methane to simulate some of the processes yielding significant quantities of hydrocarbons. In addition the effect of chemically bound nitrogen will be studied by ammonia addition in the range of 100 to 4000 ppm. The gas temperature will be controlled by a variable heat exchanger and will range from 120 to 720°C in three or four increments.

In addition to establishing the emission characteristics of the various gases as a function of composition and temperature, potential control techniques will be explored for gases that yield high levels of NO. The approaches to be considered are the classical techniques of burner design and/or staged combustion. The burner design variables will allow changes in fuel and air mixing rates and should be applicable to either thermal or fuel NO. The staged combustion techniques will be primarily directed toward control of fuel NO from ammonia bearing fuels. Based on fundamental and small scale data, there is reason to believe that operating with a burner input of 60 to 70% of theoretical air and second stage air injection to complete fuel burn out will yield fuel NO levels below 100 ppm even with high ammonia levels in the input fuel.

The results of this study will complement and reinforce related low Btu gas combustion experiments being carried out under contract to EPA by IGT and Ultrasystems.

SUMMARY

This in-house research project has examined the combustion of alcohol fuels and identified potential advantages for NO_x control. The next stage is to explore emission and combustion characteristics of low Btu gases and to study applicable NO_x control techniques. The alternate liquid fuels have received only limited considerations because of limited availability; however, as these fuels are secured they will be factored into the effort.

REFERENCES

1. Hoogendoorn, Jan C., "Experience with Fischer-Tropsch Synthesis at Sasol." Symposium Papers - Clean Fuels from Coal, pp 353-336, Institute of Gas Technology, Chicago, Illinois (September 1973).

2. Duhl, R. W. and T. O. Wentworth, "Methyl Fuel from Remote Gas Sources." Presented at 11th Annual Meeting of the Southern California Section AIChE, Los Angeles, California, April 1974.

3. Martin, G. B. and M. P. Heap, "Evaluation of NO_x Emission Characteristics of Alcohol Fuels for Use in Stationary Combustion Systems." Presented at 80th National AIChE Meeting, Boston, Mass., September 9, 1975.

4. Heap, M. P. , T. M. Lowes, R. Walmsley, and H. Bartelds, "Burner Design Principles for Minimum NO_x Emission." Proceedings, Coal Combustion Seminar, EPA-650/2-73-021, pp 141-172; NTIS No. PB 224-210/AS (September 1973).

5. Robson, F. L. and A. J. Giramonti, "The Environmental Impact of Coal-based Advanced Power Systems." Symposium Proceedings Environmental Aspects of Fuel Conversion Technology, EPA-650/2-74-118, pp 237-257; NTIS No. PB 238-304/AS (October 1974).

8:30 a.m.
Assessment of Combustion and
Emission Characteristics of
Methanol and Other Alternate
Fuels
G. Blair Martin, U.S. E.P.A.

Q: Can you comment on the quality of the methanol distillate oil emulsions as characterized by dispersed phase particle size, and also, do you have any idea of the residence time of the emulsions between the point of preparation and the point of injection into your combustion?

A: We did not look at the particle size. The one thing that we did for both the oil and methanol emulsions was to spray them at a container and to watch the separation characteristics. At high water content, the emulsions tended to separate relatively quickly. The residence time between the emulsifier and the burner is fairly short in that the emulsion is formed in a device immediately before the fuel tube to the burner. The fuel tube is approximately 18 inches long from that point to the nozzle and is constructed with a 1/8 inch I.D., so the amount of fuel that's actually in the fuel tube at any one time is relatively small.

BURNER DESIGN CRITERIA FOR CONTROL OF POLLUTANT EMISSIONS FROM NATURAL GAS FLAMES

by

D. R. Shoffstall

Paper Presented at

SYMPOSIUM ON STATIONARY SOURCE COMBUSTION

Sponsored by

COMBUSTION RESEARCH SECTION OF
U.S. ENVIRONMENTAL PROTECTION AGENCY

September 24-26, 1975

Atlanta, Georgia

BURNER DESIGN CRITERIA FOR CONTROL OF POLLUTANT EMISSIONS FROM NATURAL GAS FLAMES

by

D. R. Shoffstall

Institute of Gas Technology
Chicago, Illinois 60616

ABSTRACT

This program has developed a number of simple burner modifications which resulted in significant reductions in NO emission levels. These modifications can be utilized on existing equipment or can be incorporated in the design of new combustion systems. Because of the influence of furnace geometry and multiple flame interactions on NO emission levels, these modifications may not result in the size reduction in emission levels observed during the test program. However, applying the principles of aerodynamic NO control developed by this program, coupled with the use of suitable monitoring equipment, reductions in NO emission levels up to 60% are possible.

BURNER DESIGN CRITERIA FOR CONTROL OF POLLUTANT EMISSIONS FROM NATURAL GAS FLAMES

by

D. R. Shoffstall

Institute of Gas Technology
Chicago, Illinois 60616

For 3 years, IGT has conducted a program for the Environmental Protection Agency on NO_x (nitrogen oxides: NO, nitric oxide; and NO_2, nitrogen dioxide) emissions control from natural gas combustion on a pilot-scale test furnace. The objective of the program is twofold: 1) to determine whether combustion aerodynamics can be used to control NO_x emissions from a natural gas flame and 2) if aerodynamic control is successful, to determine the lower emission limits that can be achieved by using this technique. The resulting data could be used by industry and/or burner manufacturers to aid in reducing NO_x emissions from existing combustion processes and to help in the development of new low-NO_x-emission burners.

The effect of combustion aerodynamics on NO_x emission levels was tested on a number of industrial burner types including a kiln, a flat flame, a baffle, a movable-block swirl, and a utility boiler. This paper deals primarily with the baffle burner because not only has the investigation resulted in recommended low-NO_x-emission operating conditions but also the resulting data have been used by a group of gas utility companies in the development of a burner with a 60% reduction in NO_x emissions.

RESEARCH INSTALLATION

Most of the experimental work described in this paper was conducted on the IGT rectangular test furnace, which has a 25-sq-ft cross-sectional area and a length of 15 feet. This furnace can be end- or sidewall-fired at rates up to 4 million Btu/hr. The furnace is equipped for in-the-flame sampling (Figure 1). The overall furnace system is flexible enough that the following parameters can be varied independently:

- Heat input, up to 4 million Btu/hr
- Air input, up to 40% excess

Reproduced from
best available copy.

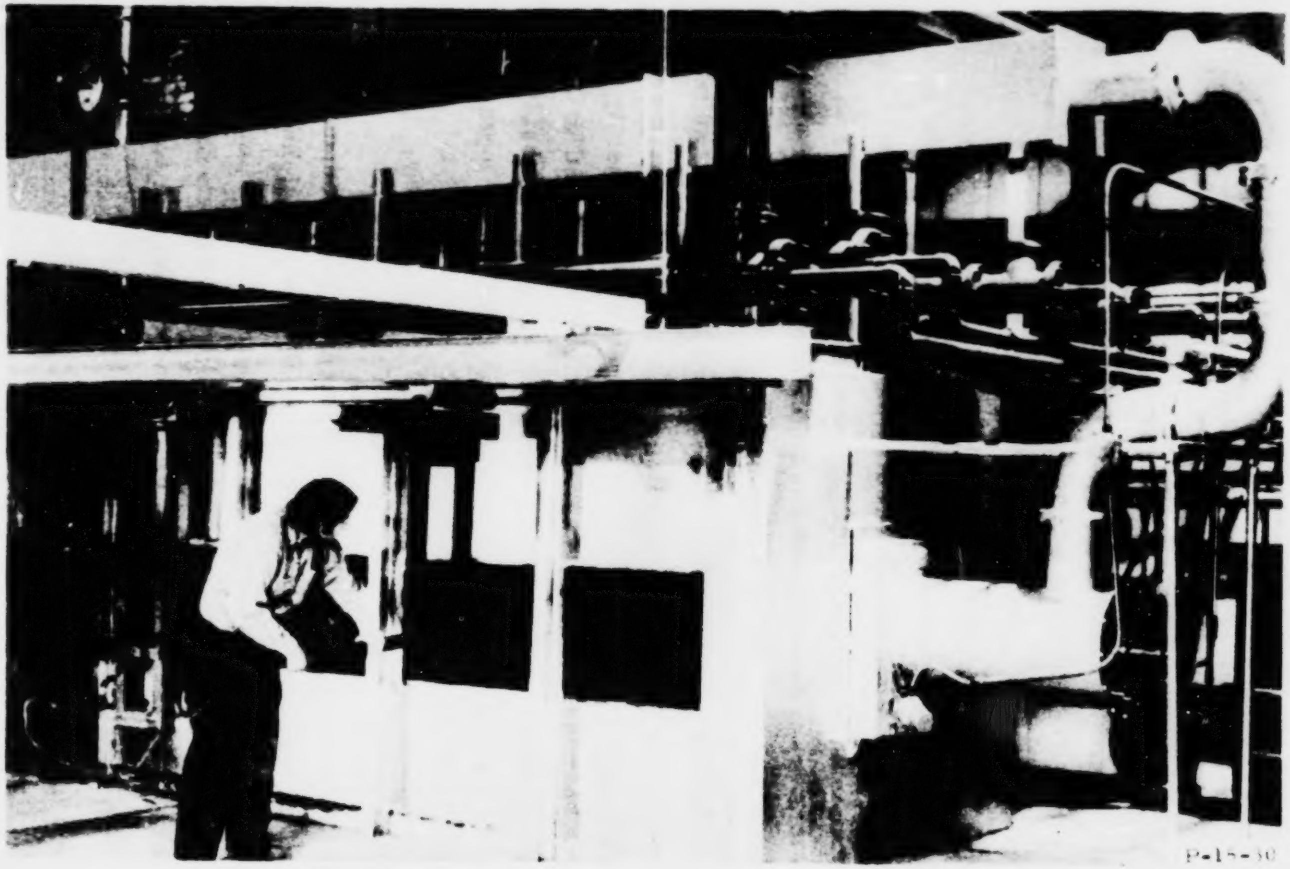


Figure 1. Rectangular test furnace

- Heat losses to the furnace wall, by changing flow in water-cooling tubes cast into the refractory furnace sidewalls
- Combustion air temperature, up to 1000°F
- External flue-gas recirculation (FGR), up to 35% of combustion air
- Furnace pressure, up to +0.05 in H_2O.

The following analytical instrumentation was used for concentration measurements of chemical species during the program (Figure 2):

- Beckman 742 Polarographic Oxygen (O_2)
- Beckman Paramagnetic Oxygen (O_2)
- Beckman NDIR Methane (CH_4)
- Beckman NDIR Carbon Monoxide (CO)
- Beckman NDIR Carbon Dioxide (CO_2)
- Varion 1200 Flame Ionization Chromatograph (Hydrocarbon C_1-C_9)
- Beckman NDIR Nitric Oxide (NO)
- Beckman NDUV Nitrogen Dioxide (NO_2)
- Hewlett-Packard Thermoconductivity Chromatograph Hydrogen (H_2), Nitrogen (N_2), Argon (Ar), O_2, CO, CO_2, and hydrocarbons C_1 to C_5
- Beckman Chemiluminescent NO-NO_2.

GENERAL FLAME CHARACTERISTICS

A general aerodynamic characterization of a flame can be made by determining the different types of flow patterns that exist within a combustion chamber. A detailed flow analysis of a confined flame reveals that the front section of a combustion chamber can be divided into four zones: primary jet, primary recirculation, secondary jet, and secondary recirculation. The primary and secondary jets contain only particles with a forward flow direction (away from the burner), whereas the recirculation zones contain gas particles moving in the reverse flow direction (back toward the burner). The size, shape, and particle density of the recirculation zones are determined by the velocity, the ratio of gas to air, the spin intensity of the secondary jet, the burner-block angle, and, for the secondary recirculation zone, the size and shape of the combustion chamber. Figure 3 shows the three types of flow patterns that we observed during our pollution control trials.

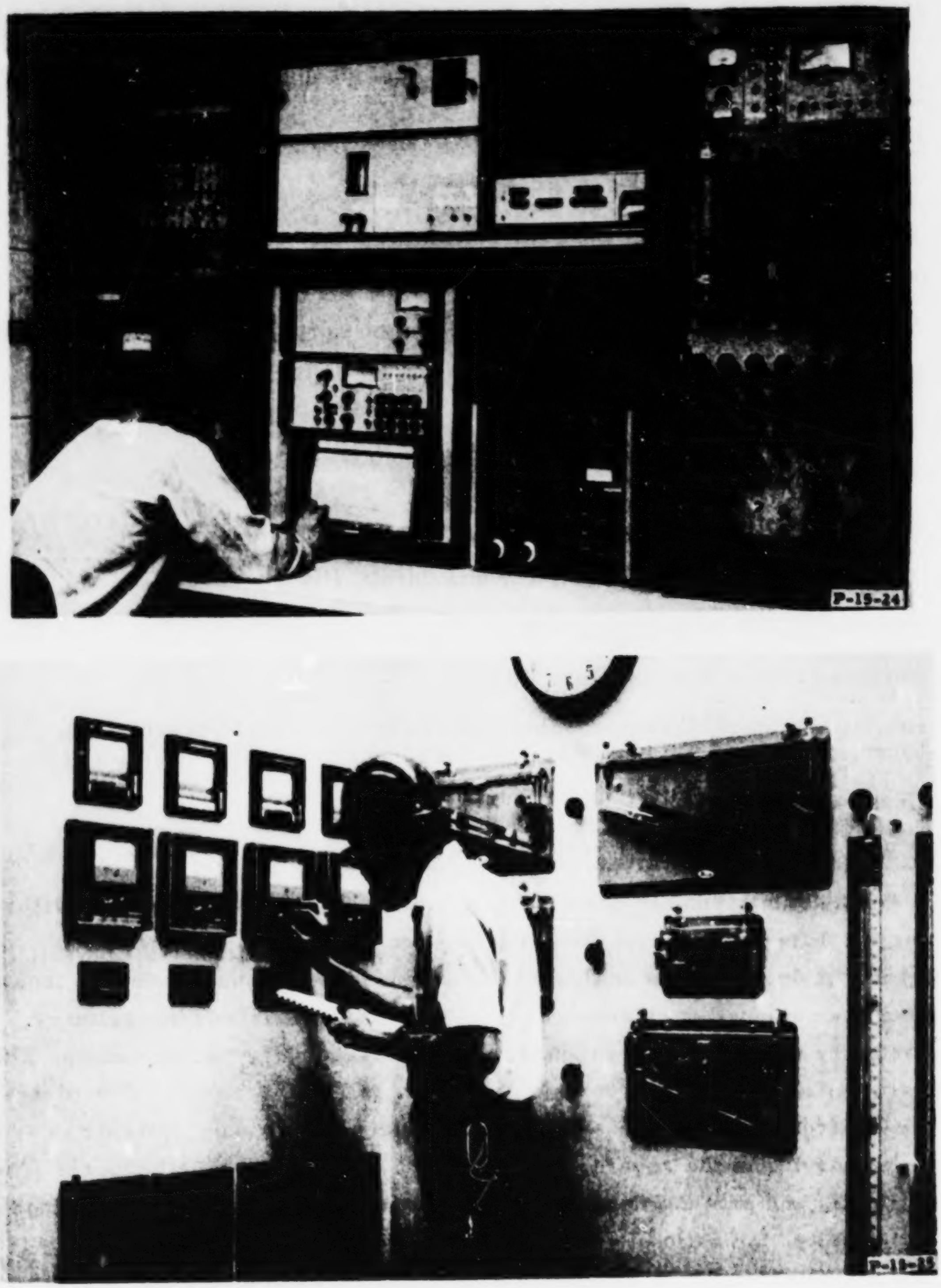

P-19-24
P-19-25

Figure 2. Control room facility

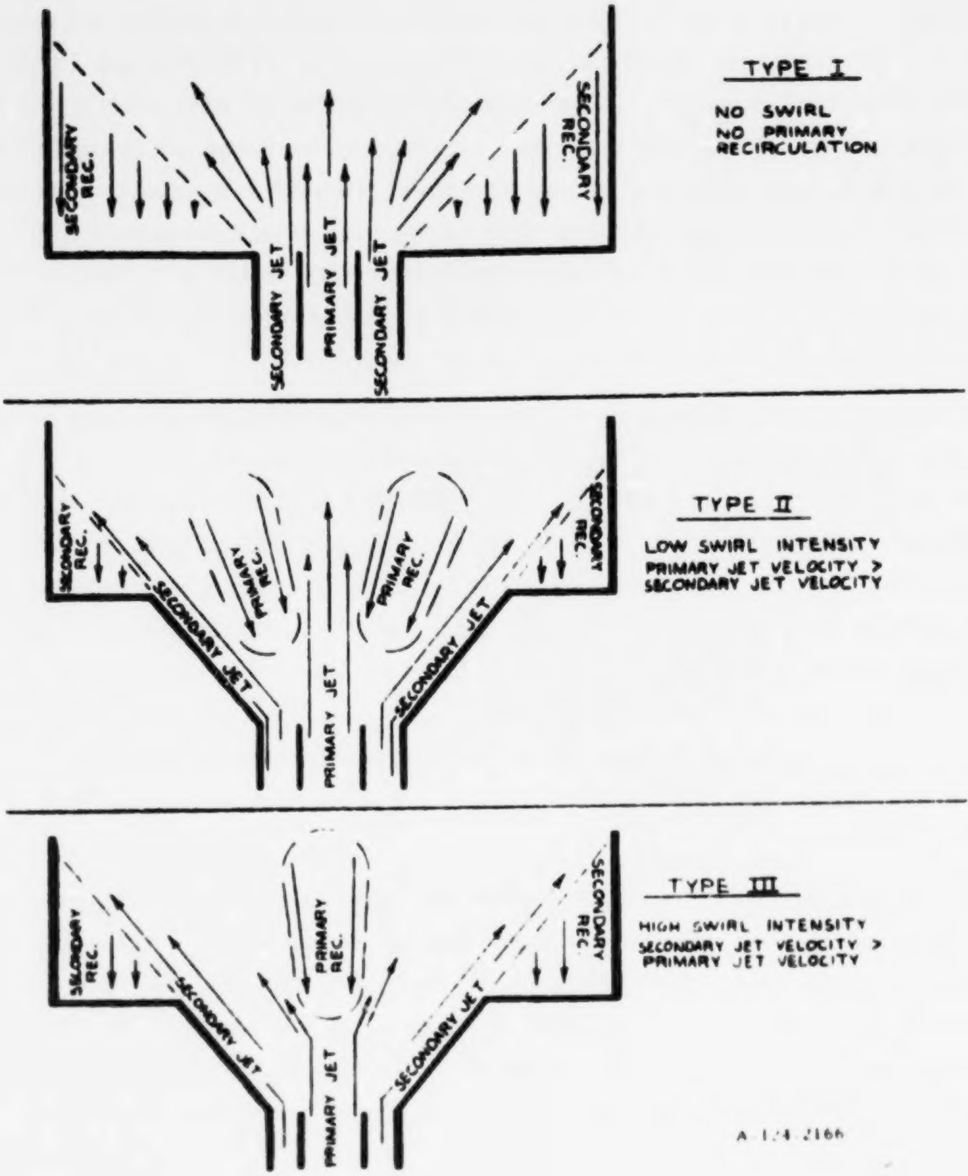

TYPE I
NO SWIRL
NO PRIMARY RECIRCULATION
SECONDARY REC.
SECONDARY REC.
SECONDARY JET
PRIMARY JET
SECONDARY JET
TYPE II
LOW SWIRL INTENSITY
PRIMARY JET VELOCITY > SECONDARY JET VELOCITY
SECONDARY REC.
PRIMARY REC.
PRIMARY REC.
SECONDARY REC.
SECONDARY JET
PRIMARY JET
SECONDARY JET
TYPE III
HIGH SWIRL INTENSITY
SECONDARY JET VELOCITY > PRIMARY JET VELOCITY
SECONDARY REC.
PRIMARY REC.
SECONDARY REC.
SECONDARY JET
PRIMARY JET
SECONDARY JET
A-124-2166

Figure 3. Flames types tested

A type I flow pattern is observed when the secondary jet has no tangential velocity component (no spin) and the primary jet velocity is much larger than the secondary jet velocity. Depending on the initial jet exit velocity from the fuel injector, the flame can be either attached to or detached from the injector. A type I flow pattern also can be generated with a secondary jet with a tangential velocity component (spin) if the burner-block divergent angle is equal to or less than the angle of the secondary jet relative to the burner axis. As a result, the burner block restricts the expansion of the secondary jet and inhibits the formation of a primary recirculation zone.

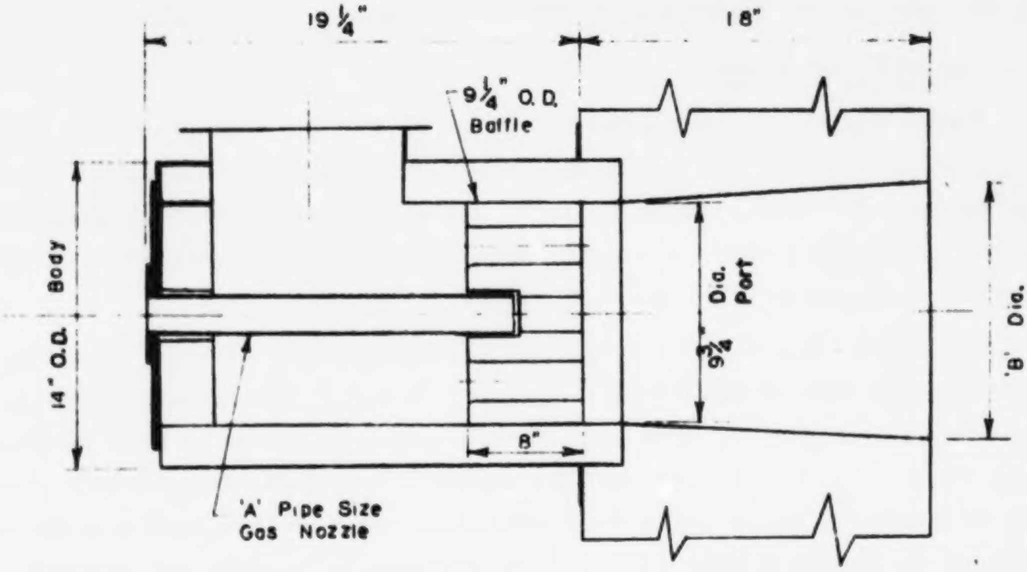
A type II flow pattern is generated when the secondary jet has a tangential velocity component large enough to cause the particles to adhere to and pack tightly against the burner block. This packing creates a low or negative pressure region in the center of the burner block. The pressure differential between the furnace and the central region of the burner block causes gas molecules to be pulled into this region and back toward the burner, thus creating the primary recirculation zone. When the velocity of the primary jet is greater than the velocity of the recirculating gases in the primary recirculation zone, the primary jet penetrates this reverse flow region and a recirculation lobe occurs on each side of the burner axis. This flow pattern is labeled type II.

If the central region of the burner block has a large enough negative pressure differential relative to the furnace, such that the velocity of the recirculating gases is greater than the velocity of the primary jet, penetration of the primary recirculation zone is not possible and a type III flow pattern results. A type III flow pattern also can be generated mechanically by introducing the fuel with only a radial velocity relative to the axis of the burner.

DATA ANALYSIS AND DISCUSSION

Baffle Burner

Figure 4 illustrates the design of the baffle burner. The gas nozzle lies parallel to and along the axis of the burner. It is inserted into the ceramic baffle, thus ensuring that the gas enters parallel to the axis of the baffle burner. Combustion air enters perpendicular to the axis and passes through the six ports in the baffle, which impart a swirl to the air in some designs.


19 1/4"
18"
9 1/4" O.D. Baffle
14" O.D. Body
9 3/4" Dia. Port
'B' Dia.
8"
'A' Pipe Size Gas Nozzle

	'A'	'B'	Baffle
Long Flame	1 1/4"	11 1/4"	Straight Thru Holes
Short Flame	2"	14 3/4"	25° Spin
Inter. Flame	2"	11 1/4"	15° Spin

Figure 4. Assembly drawing of baffle burner

Two of these baffle ports are shown in Figure 4 with their axes parallel to the axis of the burner. Air exiting from the ports (as illustrated) would have an axial velocity component only, resulting in a "long" flame. To shorten the flame length, a tangential-flow component must be added to the combustion air velocity. This is accomplished by using a baffle where the combustion-air ports are rotated relative to the axis of the burner. For the "intermediate" flame length baffle (IFLB), the rotation orientation of the ports is 15 deg, and for the "short" flame length (SFLB), 25 deg.

Standard Conditions

Figure 5 presents normalized nitrogen oxide (NO) versus excess oxygen (O_2) test data for burner conditions normal to an industrial situation (standard gas nozzle, baffle nozzle position, and 4 deg burner-block angle). Photographs illustrating flame geometry and flame luminosity with these industrial conditions are shown in Figures 6 and 7.

The standard gas nozzle is a 2-inch pipe that rests within a centering tube mounted between the baffle and the burner housing. Gas nozzle positions are illustrated in Figure 8. The gas nozzle position is denoted as the baffle position when the nozzle is even with the burner-block side of the baffle. Other nozzle positions investigated were the throat position (gas nozzle midway between the baffle and the front wall of the furnace) and the exit position (gas nozzle even with the front wall of the furnace). For the IFLB, the exit gas nozzle position produced unstable combustion and therefore is not included in the test results.

At a gas input of 3000 SCF/hr, the relationship between NO and excess O_2 became increasingly nonlinear as a function of temperature; see Figure 5. This indicates that in the range of excess O_2 we investigated, the higher the preheat, the more closely the NO-versus-O_2 relationship characterizes that of a premix flame.

For the second set of curves in Figure 5, burner conditions were the same, but the gas input was reduced to 2000 SCF/hr. In an attempt to maintain the same level of bulk NO formation, the wall temperature was held at 1420°C, compared with 1435°C for a gas input of 3000 SCF/hr. These curves show the same linear relationship between NO and excess O_2 that was observed for the kiln burner. This linear relationship is characteristic of a diffusion flame.

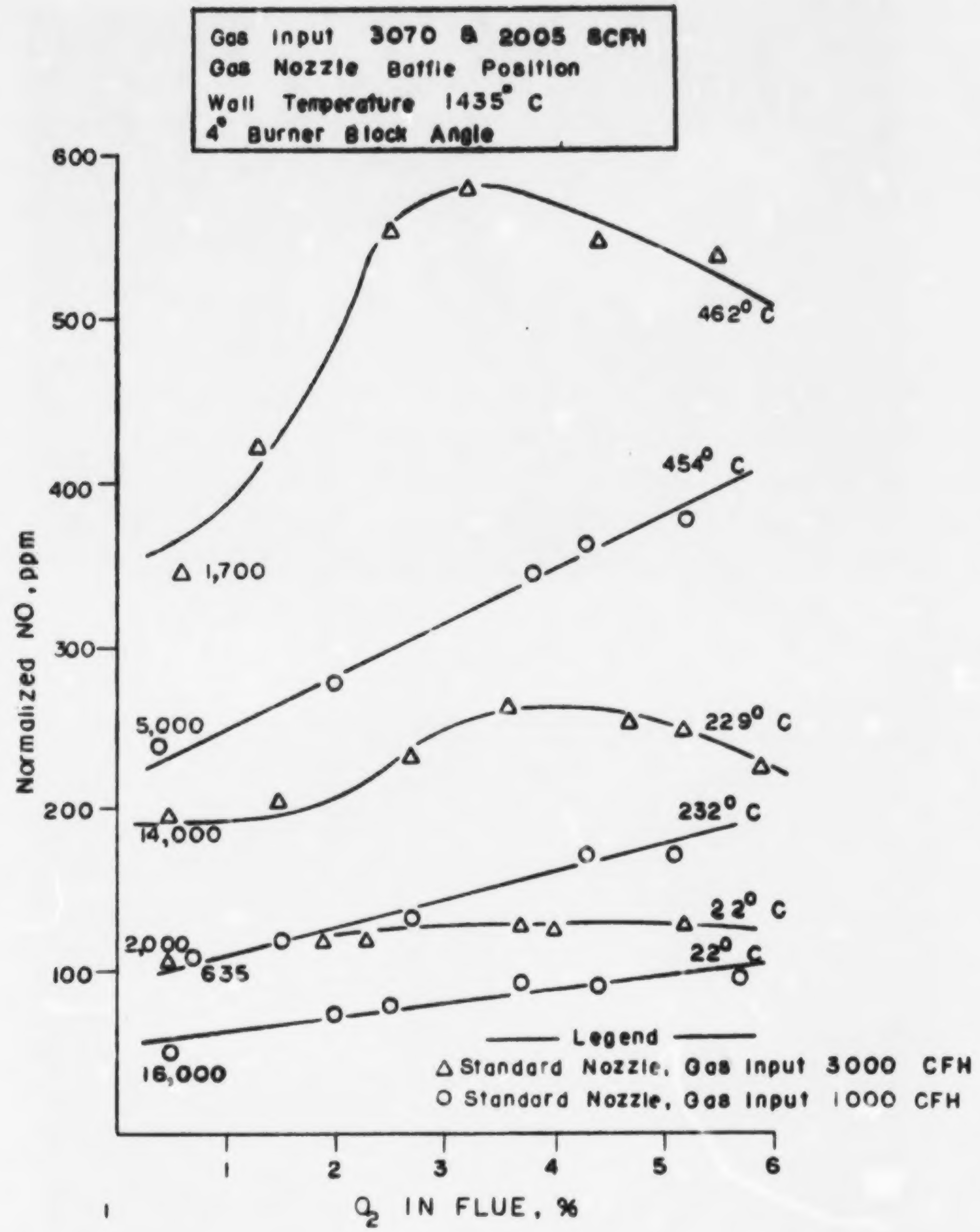
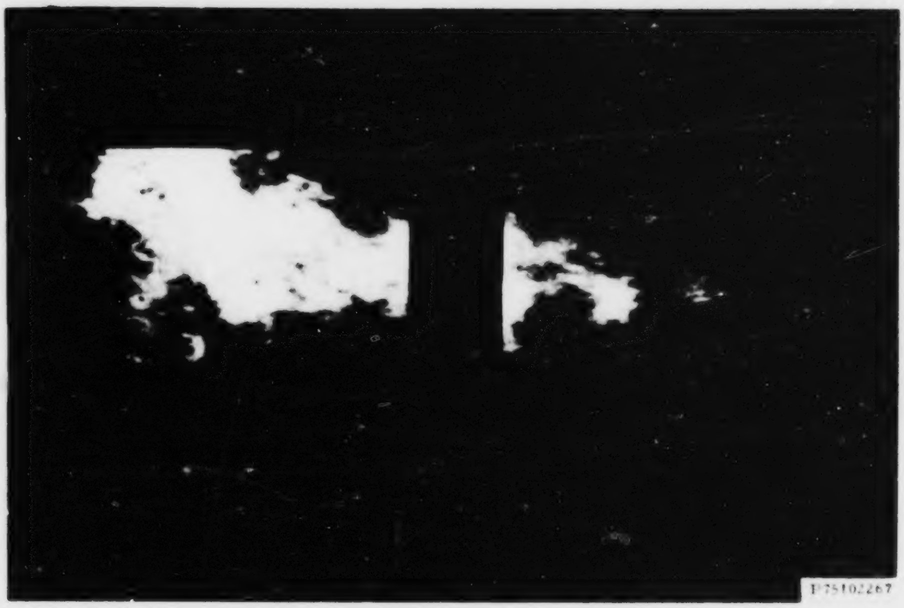
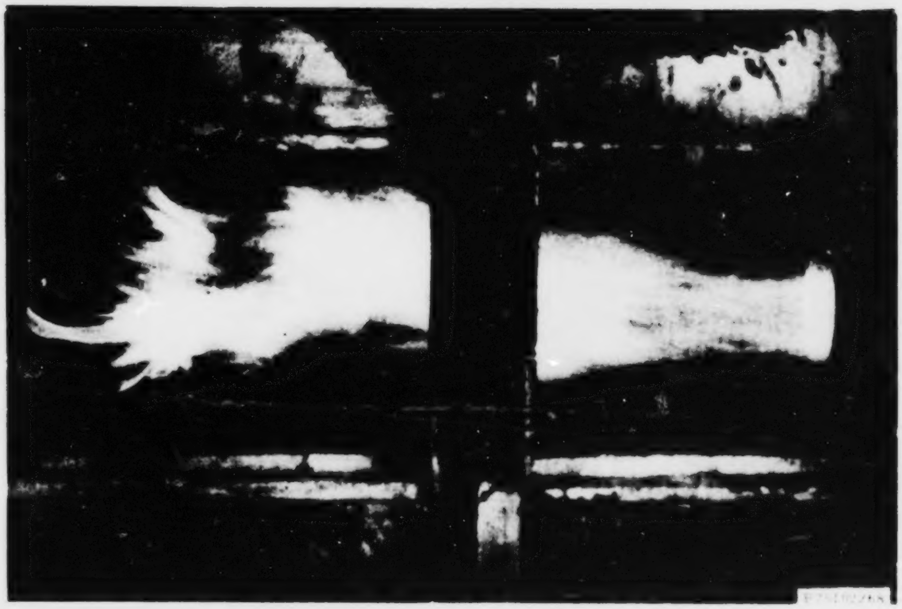


Figure 5. Normalized NO concentration as a function of flue O_2 for the IF LB burner with a standard gas nozzle at gas inputs of 3070 and 2005 SCF/hr

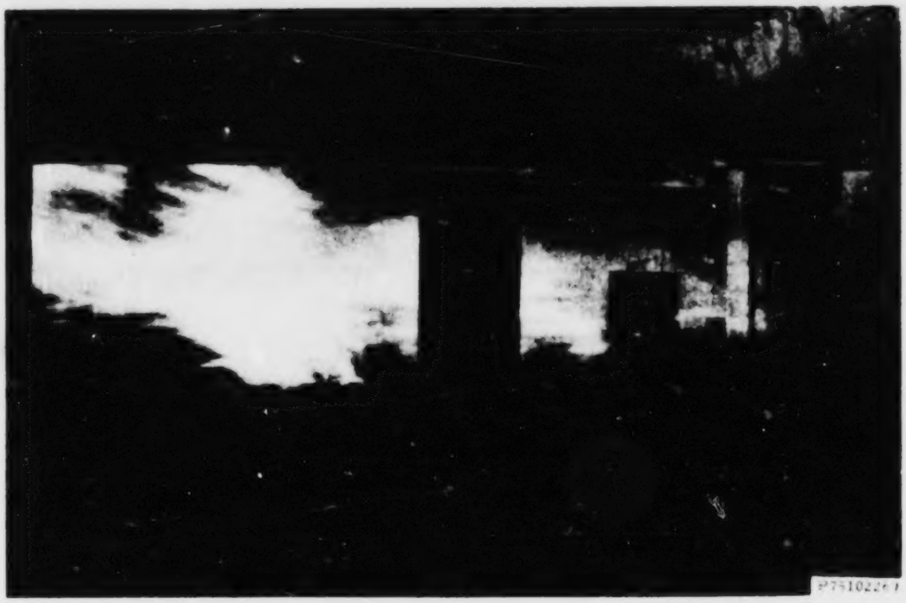


1. Divergent fuel nozzle

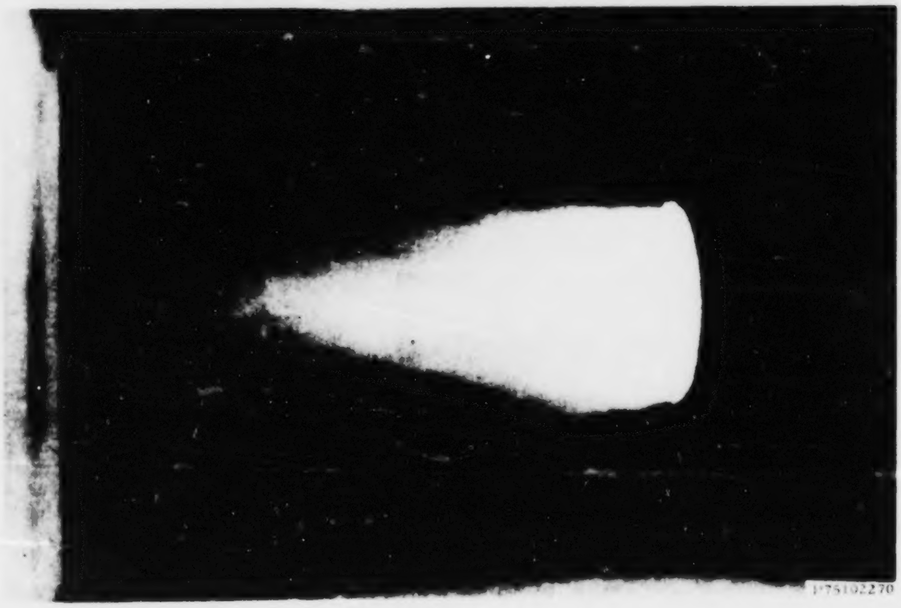


2. Standard fuel nozzle

Figure 6. Flame photographs of intermediate flame length baffle burner



3. Combination fuel nozzle



4. Radial fuel nozzle

Figure 7. Flame photographs of intermediate flame length baffle burner

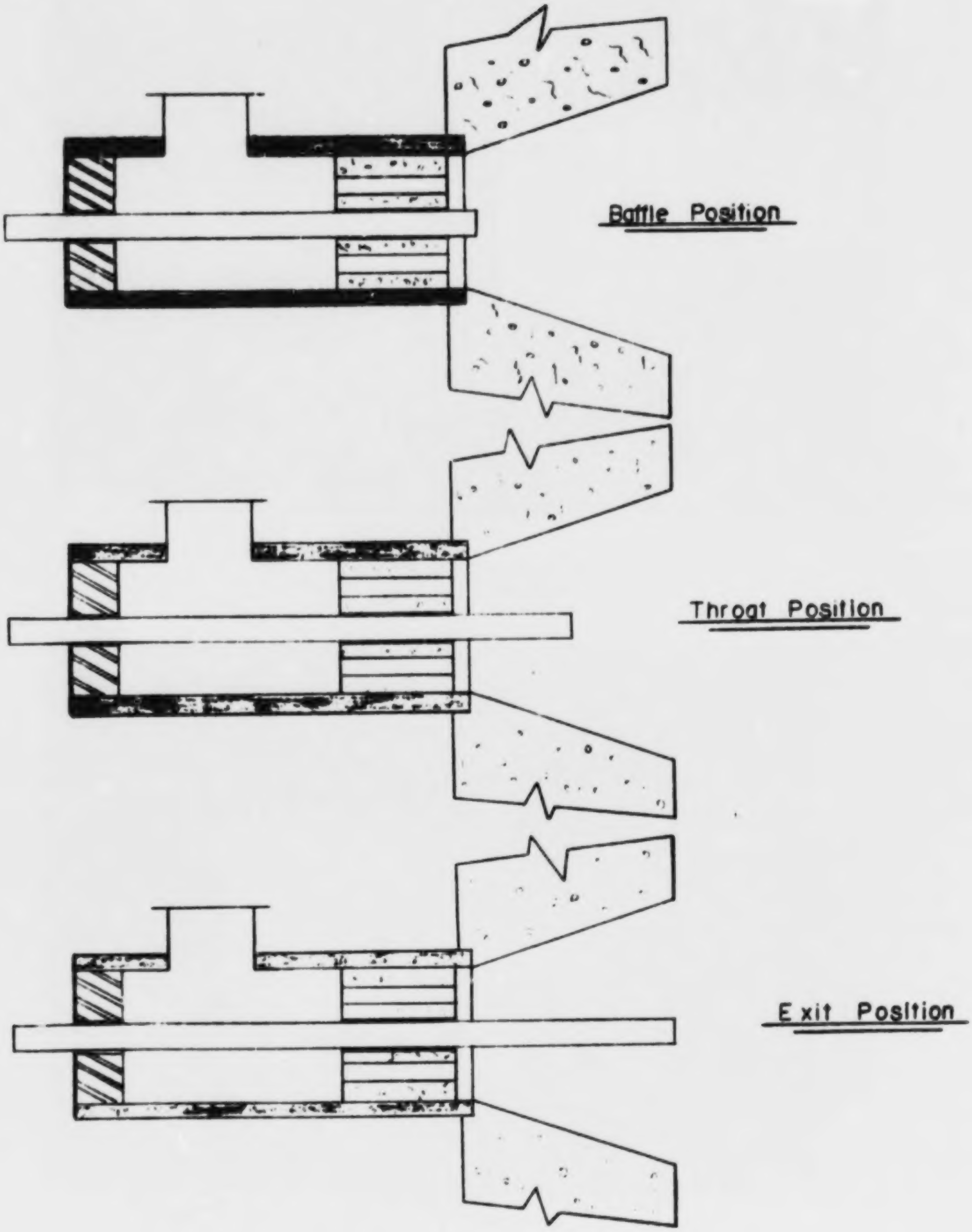

Baffle Position
Throat Position
Exit Position

Figure 8. Nozzle positions tested for the baffle burner

External FGR

As a base-line control case, the effect of external FGR was tested. The percentage of FGR is determined by using the relationship –

$$\% \text{ FGR} = \frac{\text{FGR (CF/hr)}}{\text{Secondary Air (CF/hr)} + \text{FUEL (CF/hr)}} \times 100$$

By using the data presented in Figure 9, the NO concentration measured for standard burner operating conditions with 462°C secondary air preheat can be compared with the concentration at similar burner conditions but with the addition of 15% and 30% FGR to the secondary air. During preheat, both the flue gas and secondary air were blended and reached the same final preheat temperature, which in this particular test was 460°C. At 3% excess O_2, a 15% FGR level reduced the normalized NO from 575 to 160 ppm, whereas 30% FGR reduced the measured NO concentration to 50 ppm.

Wall Temperature

The data for Figure 10 were collected with the burner operating in the normal industrial mode; however, the wall temperature was decreased from 1435° to 965°C by using water-cooling tubes within the furnace sidewalls. Although the NO was depressed by approximately a factor of 2, it is difficult to say what part, if any, was due to a reduction in the bulk NO formation. Because the secondary-recirculation-zone flue products were at a much lower temperature when they became entrained by the secondary combustion air jet, a lower flame temperature resulted and, consequently, a lower concentration of NO.

Nozzle Type and Position

Figure 11 presents NO concentrations measured under standard burner conditions but with a radial gas injector. This injector forces the gas to enter the burner block radially to the axis of the burner, which causes a flame flow pattern categorized as type III. The combination gas nozzle shown in Figure 12, operating with radial injection only, was used.

The radial nozzle in the baffle position produced more NO than the standard nozzle because of the increased rate of heat release, coupled with the inability of the burner block to be used as a heat sink. However, when the radial nozzle was moved into the throat position, there was a dramatic drop

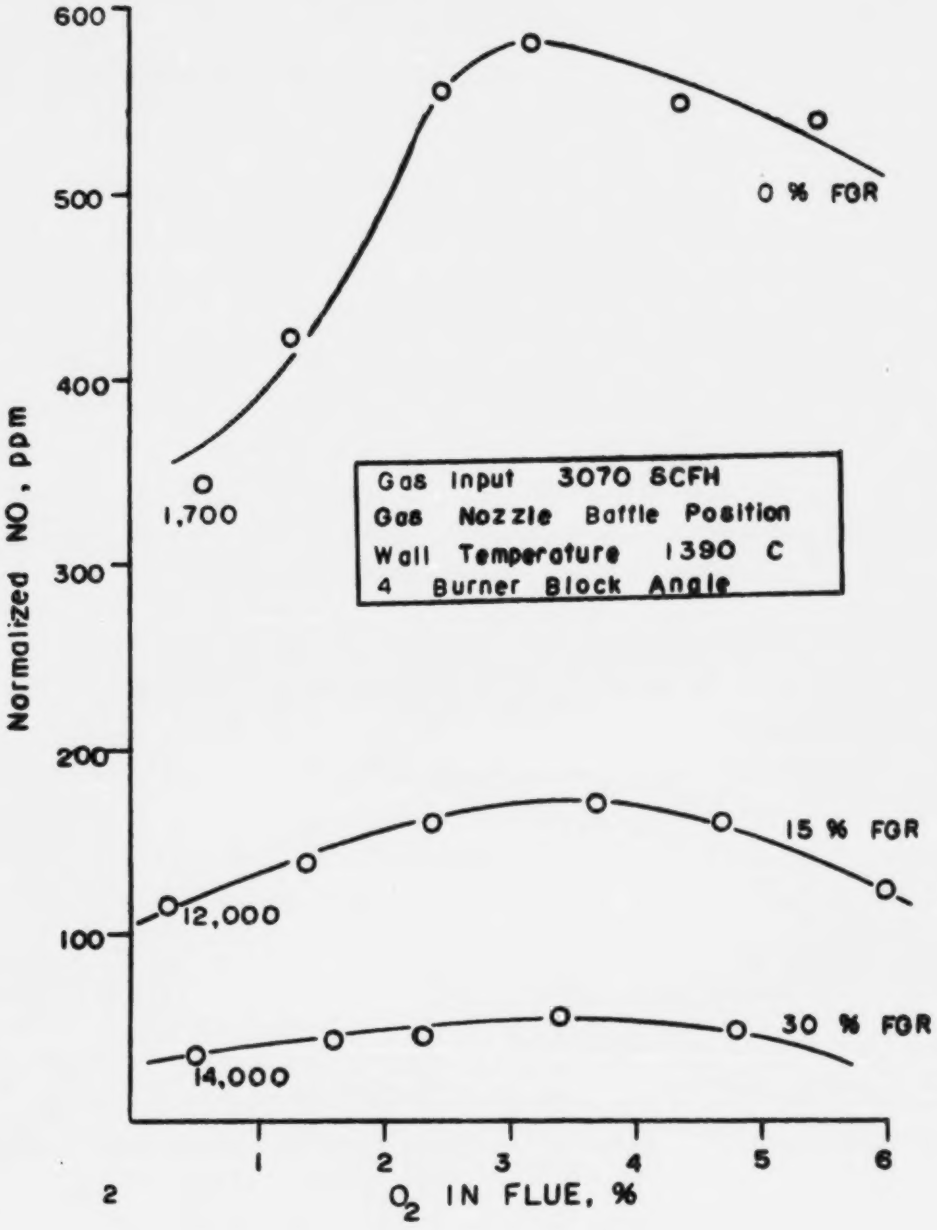


Figure 9. Normalized NO concentration as a function of flue O_2 for the IF LB burner with a standard gas nozzle and 15% and 30% FGR

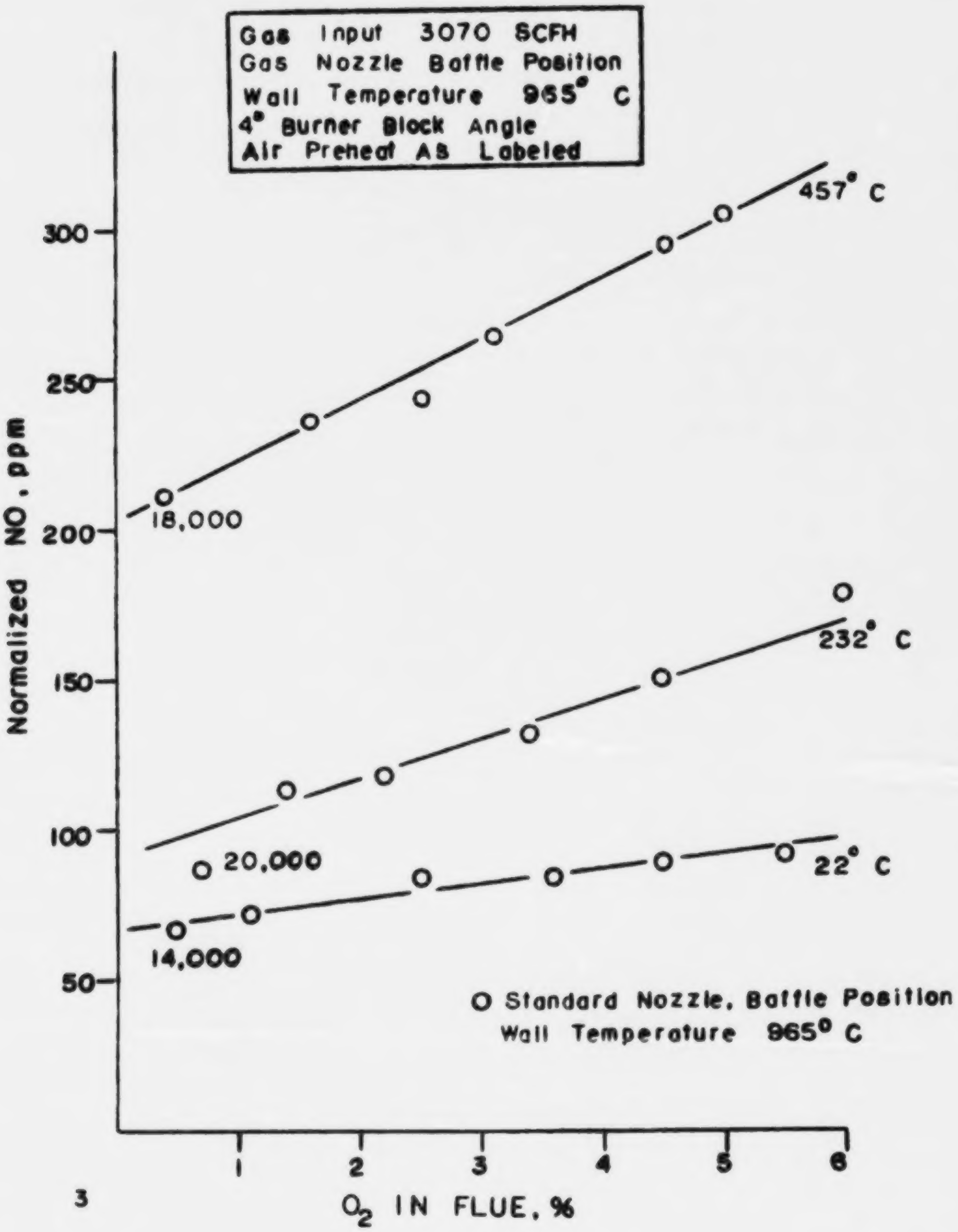


Figure 10. Normalized NO concentration as a function of flue O_2 for the IF LB burner with a standard gas nozzle at a wall temperature of 965°C

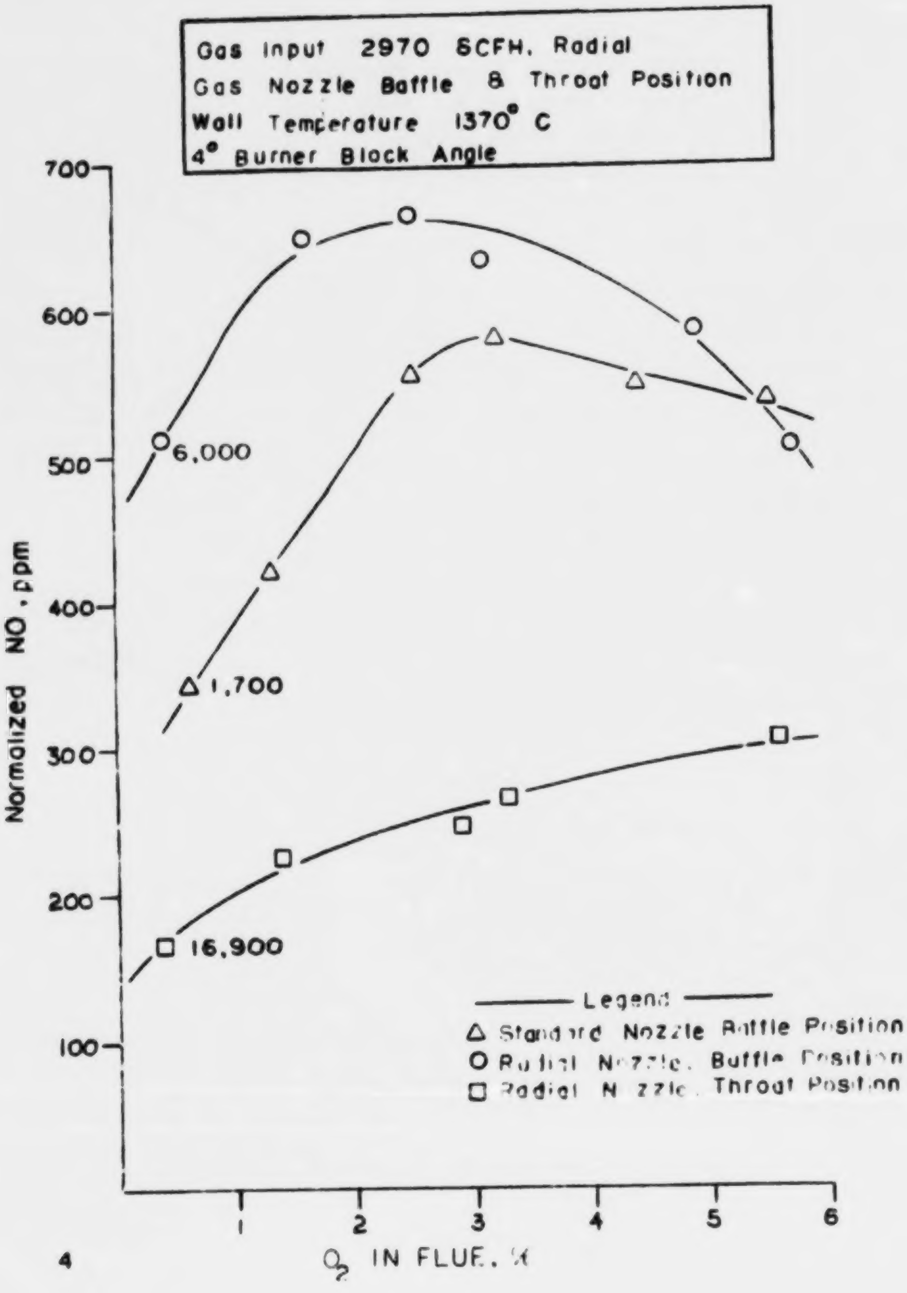


Figure 11. Normalized NO concentration as a function of flue O_2 for the IF LB burner with a combination gas nozzle and radial injection

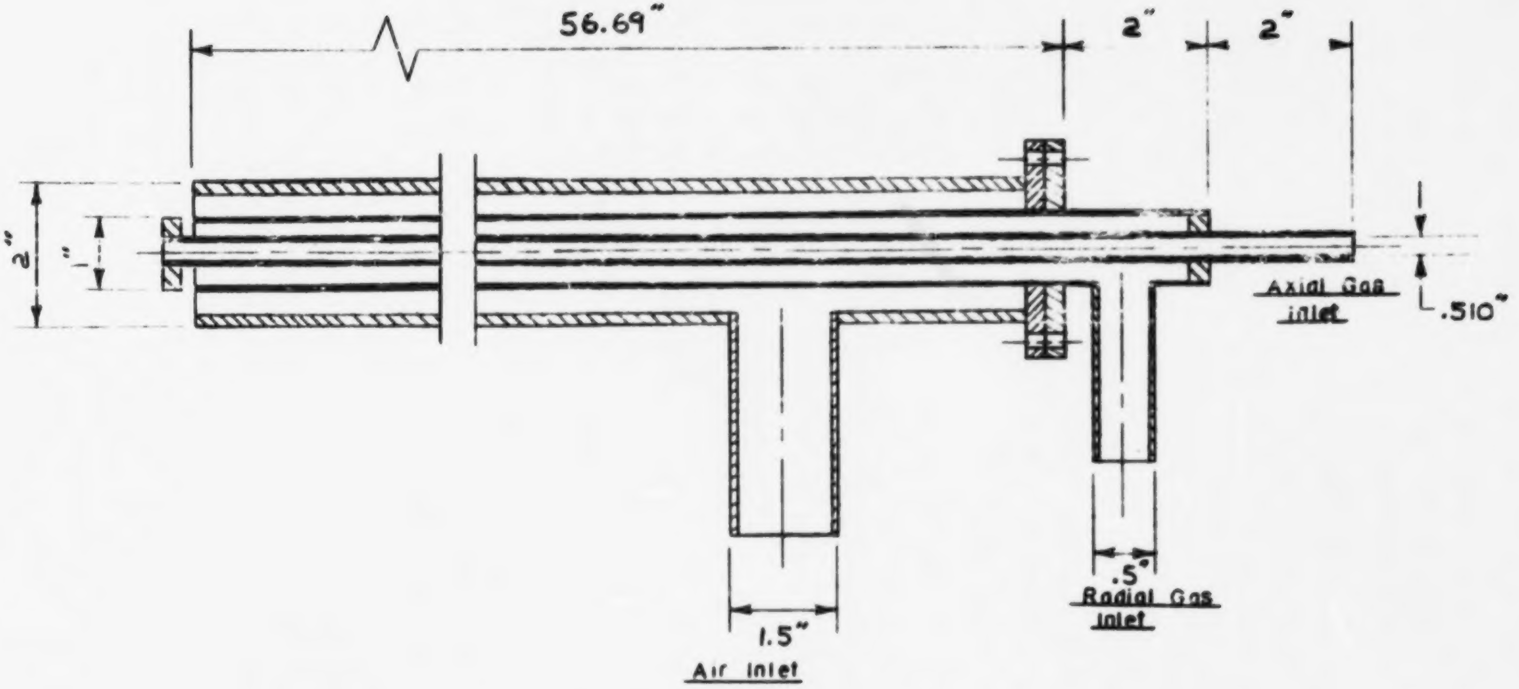

56.69"
2"
2"
2"
1"
.510"
Axial Gas inlet
.5"
Radial Gas inlet
1.5"
Air inlet

Figure 12. Combination gas nozzle

in the measured NO concentration (approximately by a factor of 2-1/2). This decrease could be due to the combustion outside the burner block, which allows a larger mass exchange to occur among the fuel, the internal recirculation zone, the secondary air, and the external recirculation zone, thus lowering the flame temperature.

In an attempt to further slow the rate of heat release, half the gas was introduced radially while the other half was introduced axially (at a high velocity of approximately 300 ft/s). Again, data were collected for the half axial-half radial injection in both the baffle and throat positions. These results are presented in Figure 13. The axial gas injection had the desired effect: It decreased the NO concentration relative to all-radial injection by projecting the flame further into the furnace and slowing the rate of heat release. Again, moving the nozzle position into the throat of the burner block further reduced the NO concentrations.

Figure 14 is a composite plot showing all significant reductions in NO as a function of nozzle type and/or nozzle position. All these data were collected with a secondary air preheat at 460°C. The base-line conditions were those of the standard nozzle in the baffle position; this burner configuration produced the highest NO concentrations. Moving the standard nozzle into the throat position did not change the shape of the NO-versus-O_2 relationship, indicating that the basic mixing patterns were not dramatically altered. However, it did decrease the NO concentration to approximately 125 ppm. With a divergent gas nozzle (Figure 15) similar to the one used in the kiln burner, an additional decrease to 100 ppm NO resulted. The differences in NO concentration produced with the divergent nozzle and the standard nozzle in the throat position decreased as a function of excess O_2, until at 6% excess O_2, the NO concentrations were equal. The divergent nozzle produced a type III flame. The decrease in NO occurred because of the additional entrainment of combustion products from the primary and secondary recirculation zones. Although the data are not plotted, test results with the divergent nozzle in the throat position paralleled those with the kiln burner; i.e., the NO was increased by moving the gas injector toward the combustion chamber. The difference in NO concentration as a function of nozzle position, however, is very small.

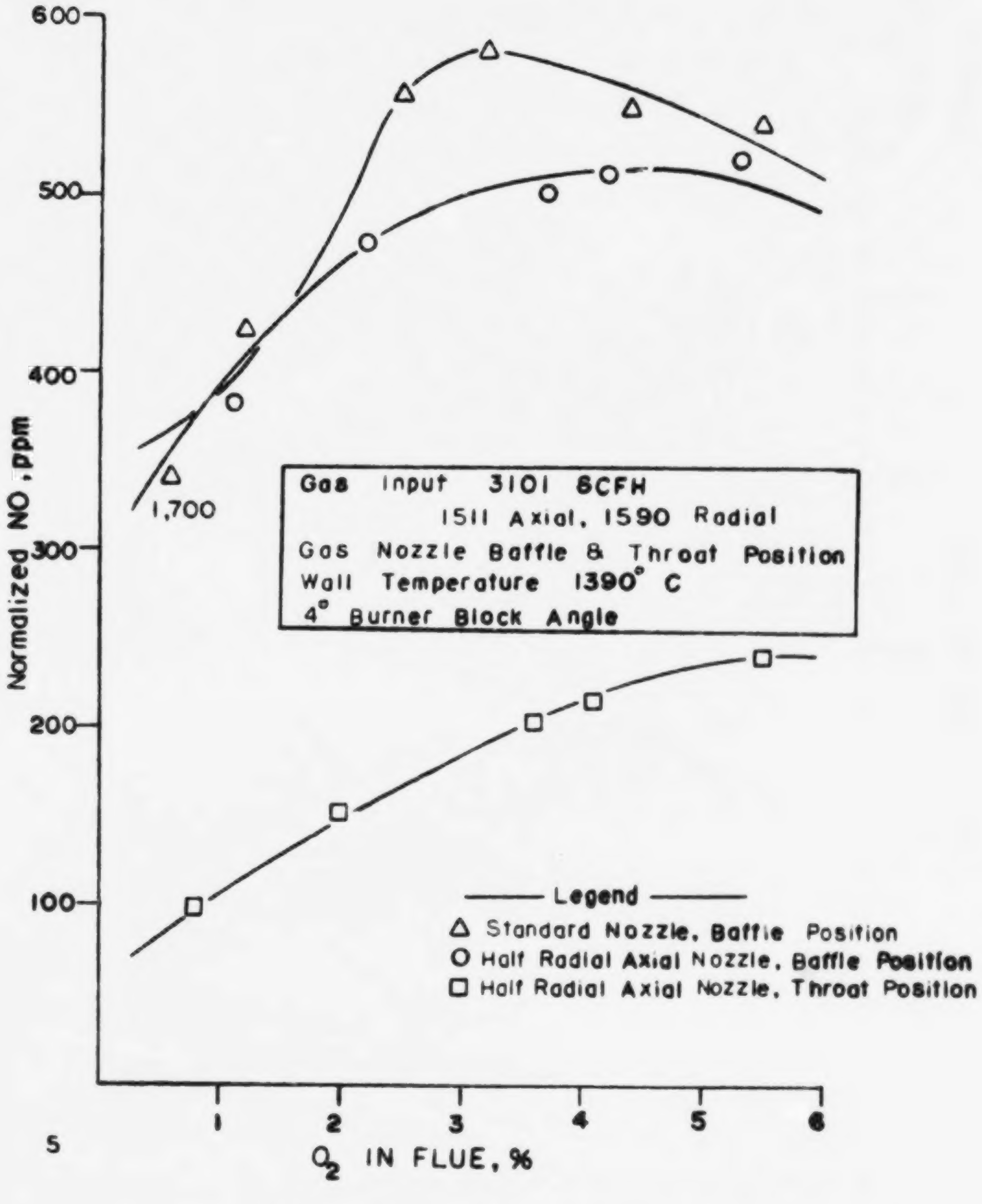


Figure 13. Normalized NO concentration as a function of flue O_2 for the IF LB burner with a combination gas nozzle and axial and radial injection

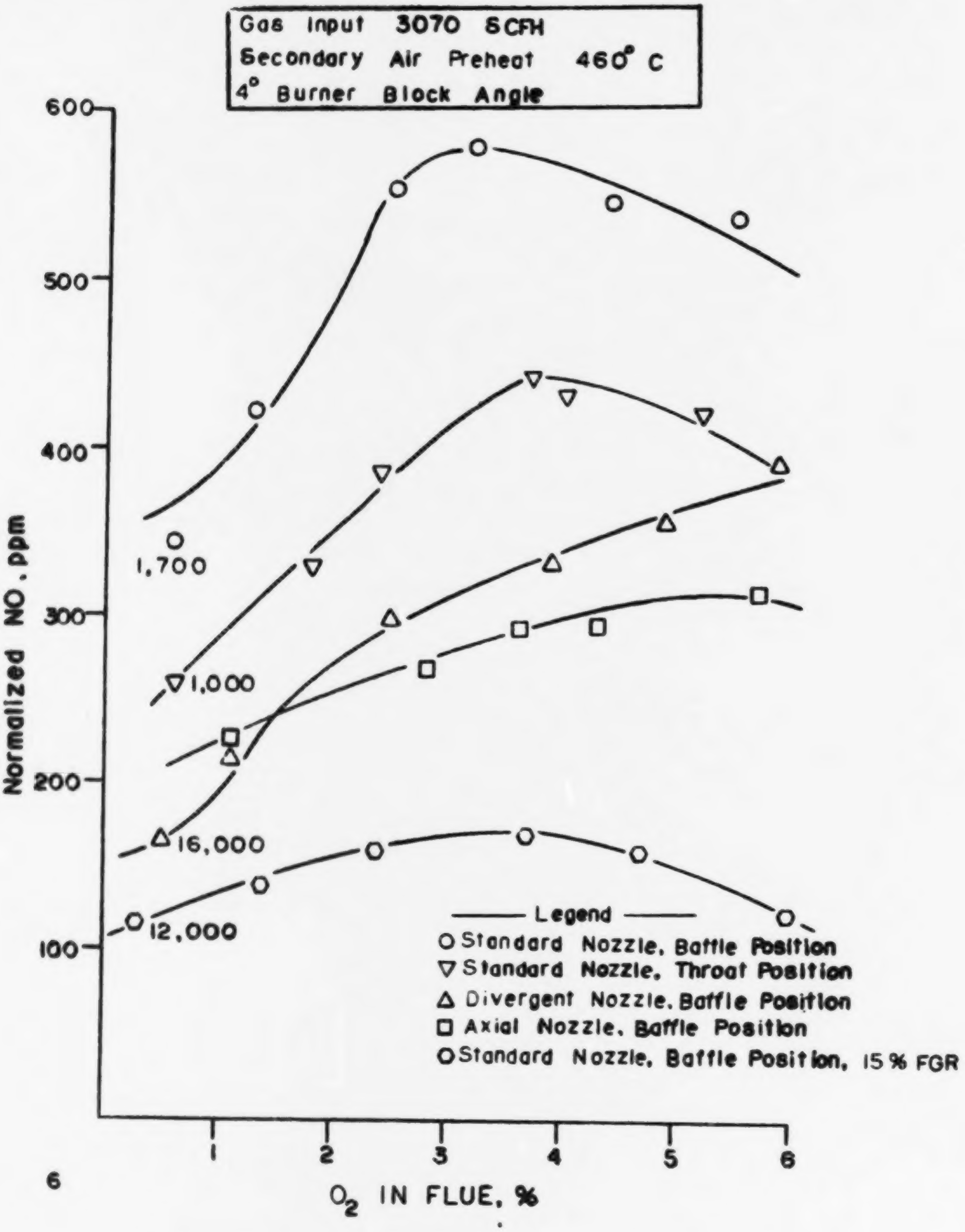
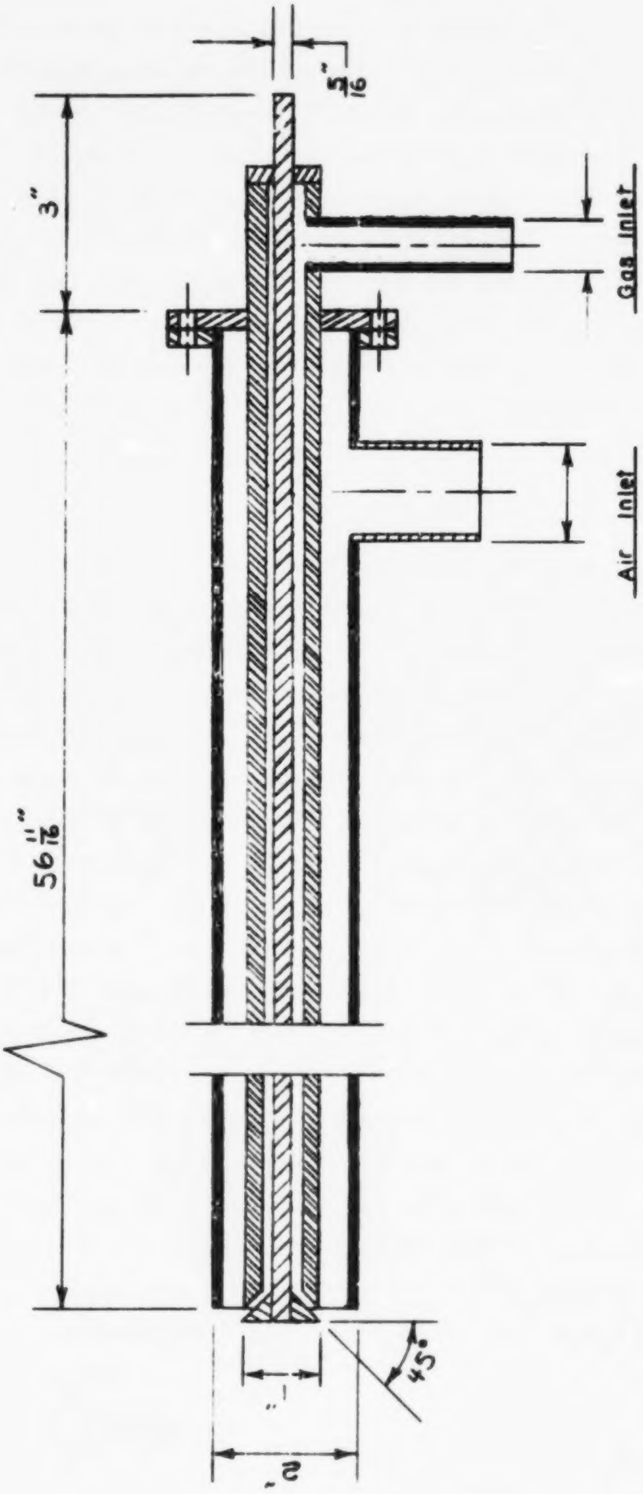


Figure 14. Normalized NO concentration as a function of flue O_2 for the IF LB burner with the various gas nozzles in different positions

10/75



5/16"
3"
56 11/16"
Gas Inlet
Air Inlet
45°
1"
2"

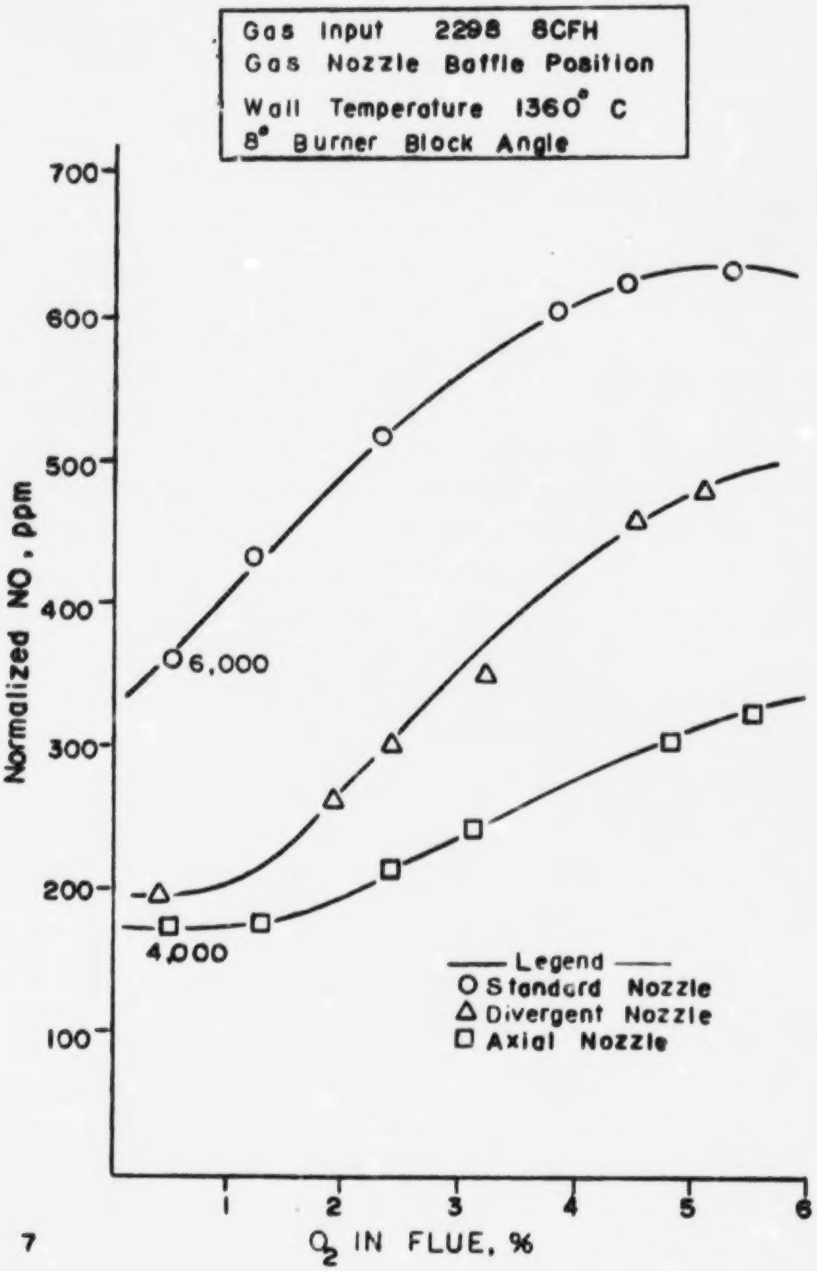
Figure 15. Divergence gas nozzle

The most dramatic decrease in NO with burner alterations occurred when the gas velocity was increased by a factor of 16. This was accomplished by using all-axial gas injection but decreasing the injector opening from the standard 2 inch to 0.5 inch. As shown in Figure 14, at less than 2% excess O_2, the divergent nozzle produced the lowest NO emissions; however, above that level of excess O_2, the high-velocity axial nozzle produced the lowest NO emissions. At 3% excess O_2 (11.4% excess air, a typical industrial level), comparing the normal burner output of 515 ppm with the high-velocity gas-injection burner output of 250 ppm, we decreased the NO pollutant level by 325 ppm through a low-cost alteration of the gas injector. Noted that external FGR remains the best depressant of NO formation that we tested. At 15% FGR, the NO level is 150 ppm with the standard baffle-and-nozzle configuration, which represents a total decrease of 425 ppm.

Burner-Block Angle

To test the influence of the primary recirculation zones on the level of NO emissions, the burner-block angle was increased from 4 to 8 deg. The primary recirculation zones contain not only combustion products but also fuel and air. The entrainment of these gases by the primary and secondary jets should help to depress the flame temperature; however, they are not as desirable as the gases in the secondary recirculation zone because they contain both fuel and air. The angular difference between the IFLB (the air ports are angled at 15 deg relative to the centerline of the baffle) and the burner block (air entry being an 8-deg divergent cone) is 7 deg. Because the angle of the ports is greater than that of the burner block, the flow will not separate from the contour of the block. The IFLB was tested with the standard, divergent, and high-velocity axial gas nozzles with an air preheat temperature of approximately 460°C. The results are graphed in Figure 16.

Table 1 compares the NO levels for integer values of the percentage of excess O_2 in the flue versus nozzle type between the 4 and 8-deg burner blocks. For the standard and divergent gas nozzles at low levels of excess air (below 12%), the emission levels from the two burner blocks are comparable. However, as the excess air is increased, the emission levels from the 8-deg block become larger than those from the 4-deg block. Use of the



7

Figure 16. Normalized NO concentration as a function of flue O_2 for the IF LB burner with standard, divergent, and axial gas nozzles

Table 1. NORMALIZED NO AS A FUNCTION OF NOZZLE TYPE, BLOCK ANGLE, AND EXCESS O_2 FOR THE IFLB BURNER WITH AN AIR PREHEAT TEMPERATURE OF 460°C

		% O_2				
		1	2	3	4	5
Nozzle Type	Block Angle, deg	ppm				
Standard	4	390	487	577	567	542
	8	408	492	564	612	636.
Divergent	4	197	273	313	340	360
	8	204	272	360	428	480
Axial	4	227	255	280	300	313
	8	174	196	238	278	313

high-velocity (611 ft/s) axial nozzle with the 8-deg block at normal operating levels of excess air (below 20%) resulted in a 20% reduction in NO emissions. Thus the desired mass exchange among the primary jet, secondary jet, and the internal recirculation zones occurs only for the high-velocity axial nozzle. In the case of the standard nozzle (38 ft/s) gas velocity) and the divergent nozzle (654 ft/s gas velocity), the increased burner volume resulted in high emissions. This increase occurred because a) the rate of heat release resulting from a high mass exchange between the primary and secondary jets improved more than the mass exchange among the primary jet, the secondary jet, and the internal recirculation zones or b) the volume of the secondary recirculation zone was decreased.

SFLB Burner

Air Velocity

Initial tests with the SFLB burner were conducted by using a high-velocity (126 ft/s) baffle and a low-velocity (80 ft/s) baffle. (Air injection ports are angled at 25 deg relative to the centerline of the baffle.) Because of the extreme pressure drop associated with the high-velocity baffle (approximately 22 in. H_2O with an air flow rate of 38,000 SCF/hr at 450 °C), the tests were conducted with a gas load of 2000 CF/hr. The 8-deg burner-block angle used in these tests is the manufacturer's recommended angle for industrial applications.

Figure 17 presents the test results as normalized NO emissions plotted against the measured percentage of O_2 in the flue. The high-velocity baffle produced consistently lower emission levels than the low-velocity baffle as

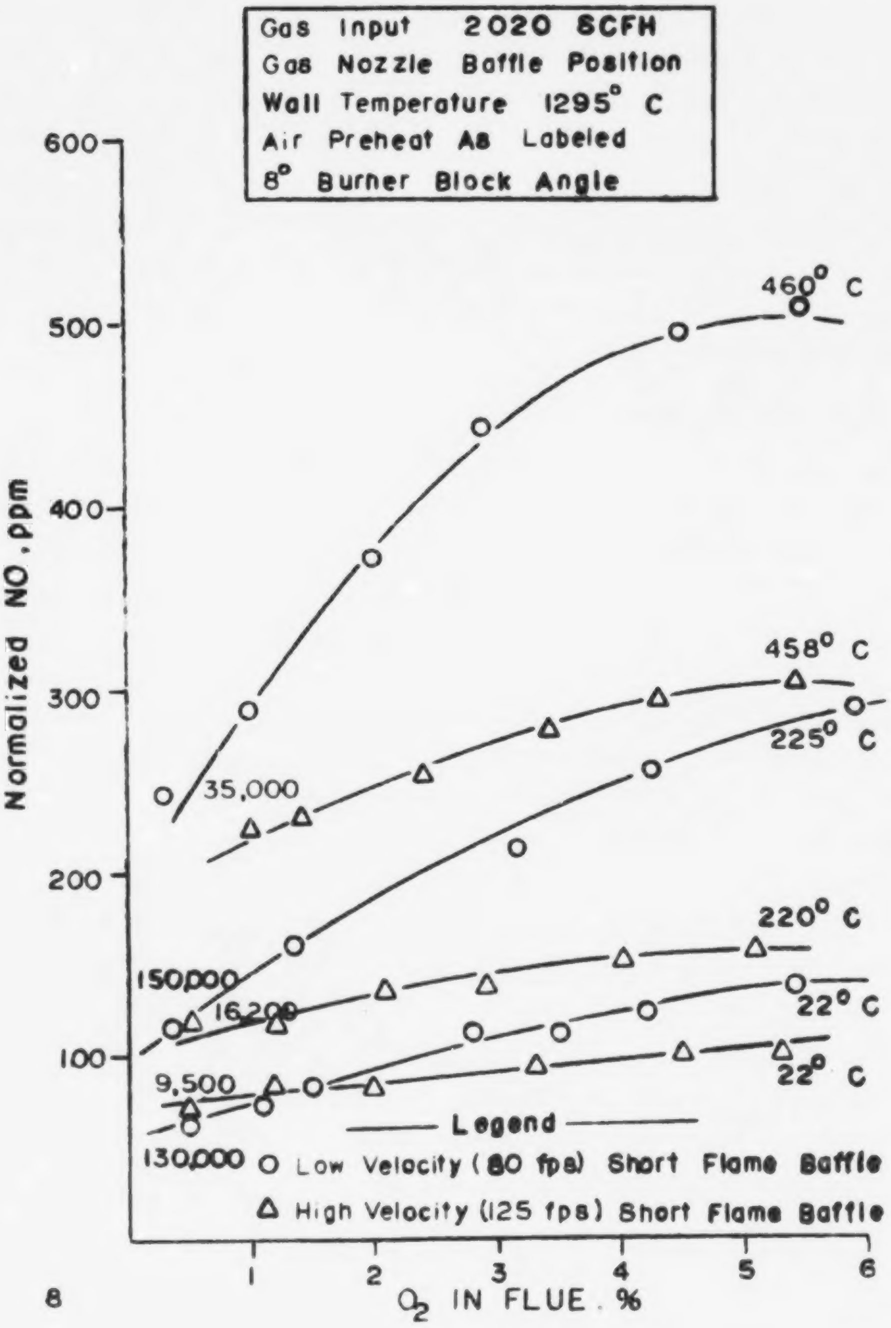


Figure 17. Normalized NO concentration as a function of flue O_2 for the SF LB burner with a standard gas nozzle

a result of the larger mass exchange between the secondary recirculation zone and the secondary jet because of the increased velocity gradient. Thus, the higher the velocity of the secondary jet, the lower the NO emission levels. The magnitude of the reduction in NO depends not only on the velocity gradient across the shear layer separating the secondary jet from the secondary recirculation zone but also on the volume and temperature of the secondary recirculation zone. The cost involved in this method of NO reduction is due to the additional fan horsepower needed to overcome the increased pressure drop in the burner.

Wall Temperature

Figure 18 illustrates the effect of wall temperature on the NO emission levels of the SFLB as a function of secondary air preheat and excess air. Conclusions similar to those for the IFLB can be drawn for the SFLB: A wall temperature as low as possible must be maintained through increased wall cooling, lowered gas input, or furnace design.

External FGR

To determine whether combustion aerodynamics can be used to recirculate combustion products to the base of the flame as an emission control technique, we simulated the idealized case (in which the combustion air and products are thoroughly mixed before ignition) by mixing flue gases with the combustion air outside the burner. Figure 19 compares the NO levels as a function of the percentage of O_2 in the flue for 0%, 15%, and 25% FGR. Again, as demonstrated for the kiln burner and the IFLB, external FGR is an extremely effective method of controlling NO emissions from the SFLB.

Nozzle Type

To determine the type of injector that would reduce NO emissions, a series of trials were conducted by using different methods of gas injection; the results are shown in Figure 20. The NO-versus-excess O_2 relationship for the standard nozzle (injection method recommended by manufacturer; 2-inch stainless-steel pipe with an inlet velocity of 38 ft/s and a gas input rate of 3000 CF/hr) is shown as a reference, so that the effect of the gas injector type on the NO emission levels can be evaluated. Visual observations were made to determine the flame length for each gas nozzle tested. This allowed a first-order evaluation of alterations that can be made to obtain the flame shape desired by the manufacturer.

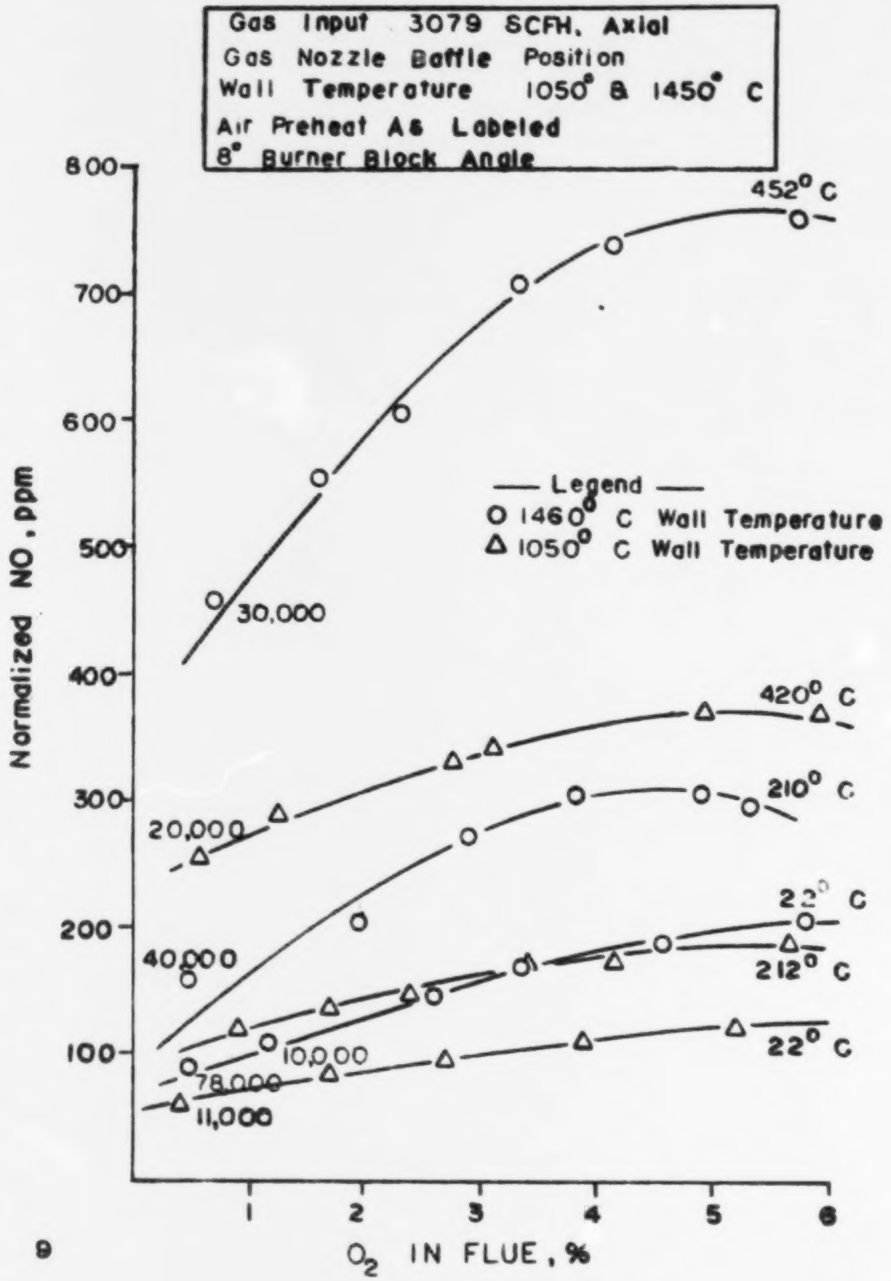


Figure 18. Normalized NO concentration as a function of flue O_2 for the SF LB burner with a standard gas nozzle at wall temperatures of 1450° and 1050°C

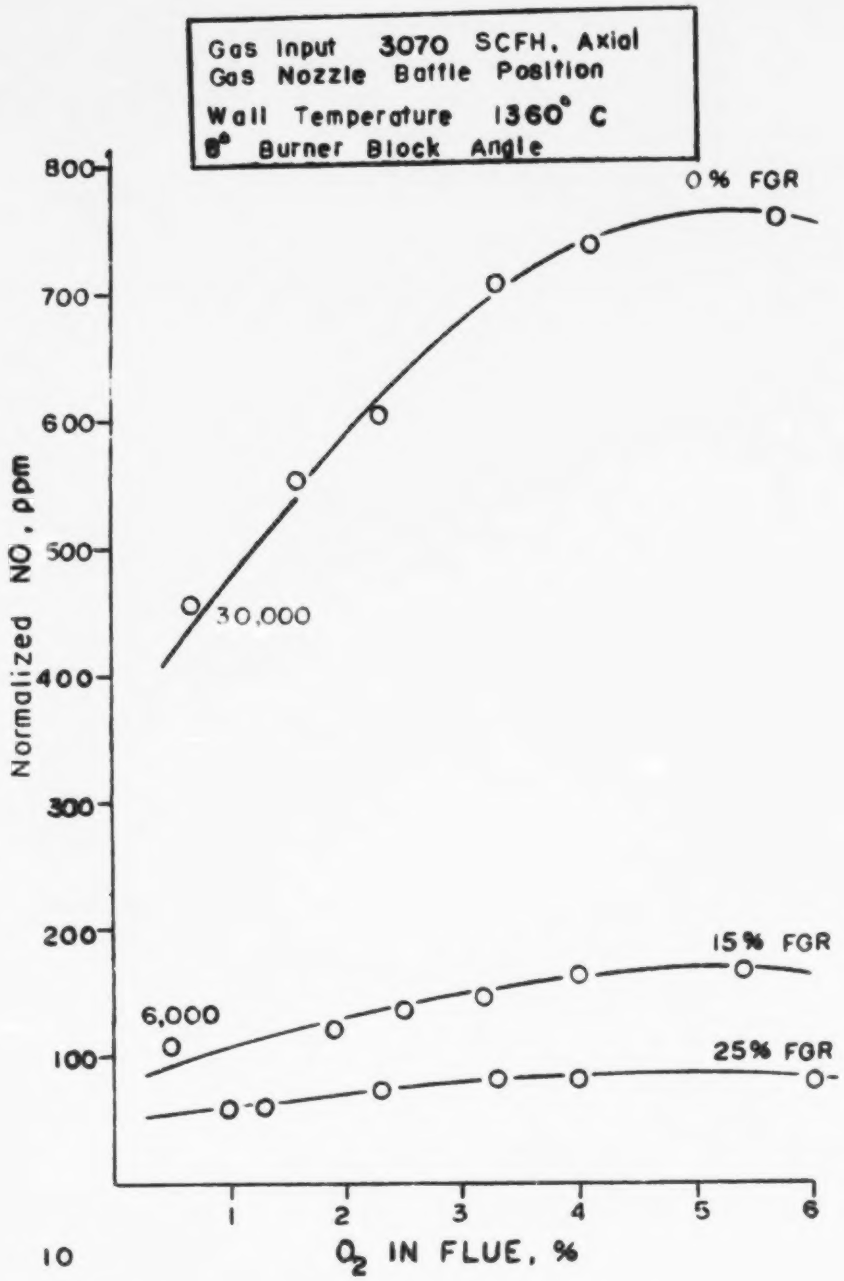


Figure 19. Normalized NO concentration as a function of flue O_2 for the SF LB burner with a standard gas nozzle and 15% and 25% FGR

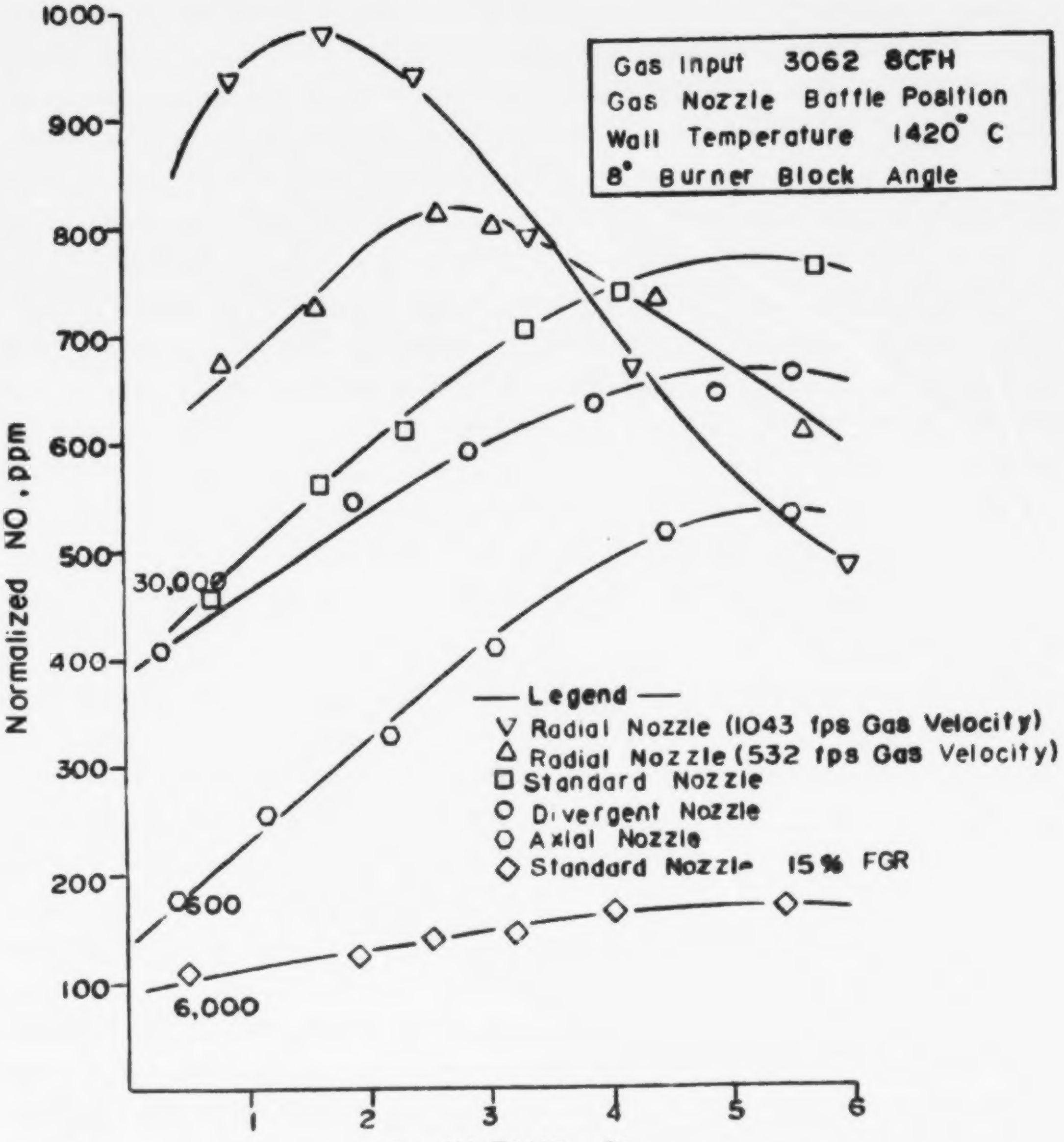


Figure 20. Normalized NO concentration as a function of flue O_2 for the SF LB burner with the various gas nozzles

The visual flame length observed with the standard gas nozzle with the SFLB was 103 cm. The high-velocity (1043 ft/s) radial injector increased the NO emissions substantially above those measured for the standard nozzle. The shape of the emission curve closely resembled that of a premixed flame; peak emissions occurred at 1.5% excess O_2. The flame was invisible. Reducing the radial velocity to 532 ft/s resulted in a shift of the maximum NO emission to an excess O_2 level of 2.3%. Because of the reduction in the radial injection velocity, the magnitude of the peak NO concentration was reduced 20%. The visual flame length was 72 cm, still 31 cm shorter than that desired. The divergent nozzle, which was the first altered gas injector tested with the SFLB, resulted in lower emission levels than the standard nozzle. The gas velocity from the divergent nozzle was 654 ft/s (at a 3000 CF/hr gas load); however, a type III flame resulted because of the wake generated by the divergent cone in the nozzle. Despite the high inlet velocity, the flame length was 113 cm, which compares favorably with the desired length of 103 cm.

The injection method that resulted in the lowest emissions was the high-velocity axial nozzle (611 ft/s and a 3000 CF/hr gas load). This nozzle produces a type II flame, even with the high-swirl SFLB, because the velocity of the gas is large enough to split the primary recirculation zone. Although the rate of entrainment per unit area between the primary jet and the surrounding flow zones increased because of the larger velocity gradient when compared with that from the standard nozzle, the flame length also increased, to 286 cm. The increased flame length was a result of a lower mass exchange rate per unit time between the primary and secondary jets. This reduced mass exchange resulted from a decrease in the area of the shear layer caused by the smaller primary jet. Thus, by delaying the mixing between primary and secondary jets, we not only slowed the heat release rate of the flame, but also approached the ideal of the EFGR by allowing more time for the secondary jet and the combustion products in the secondary recirculation zone to mix.

Burner-Block Angle

Figure 21 represents NO data from the SFLB trial with standard, divergent, and high-velocity axial nozzles and a 16-deg burner block. Obviously, the combustion aerodynamics were changed drastically as a function of excess

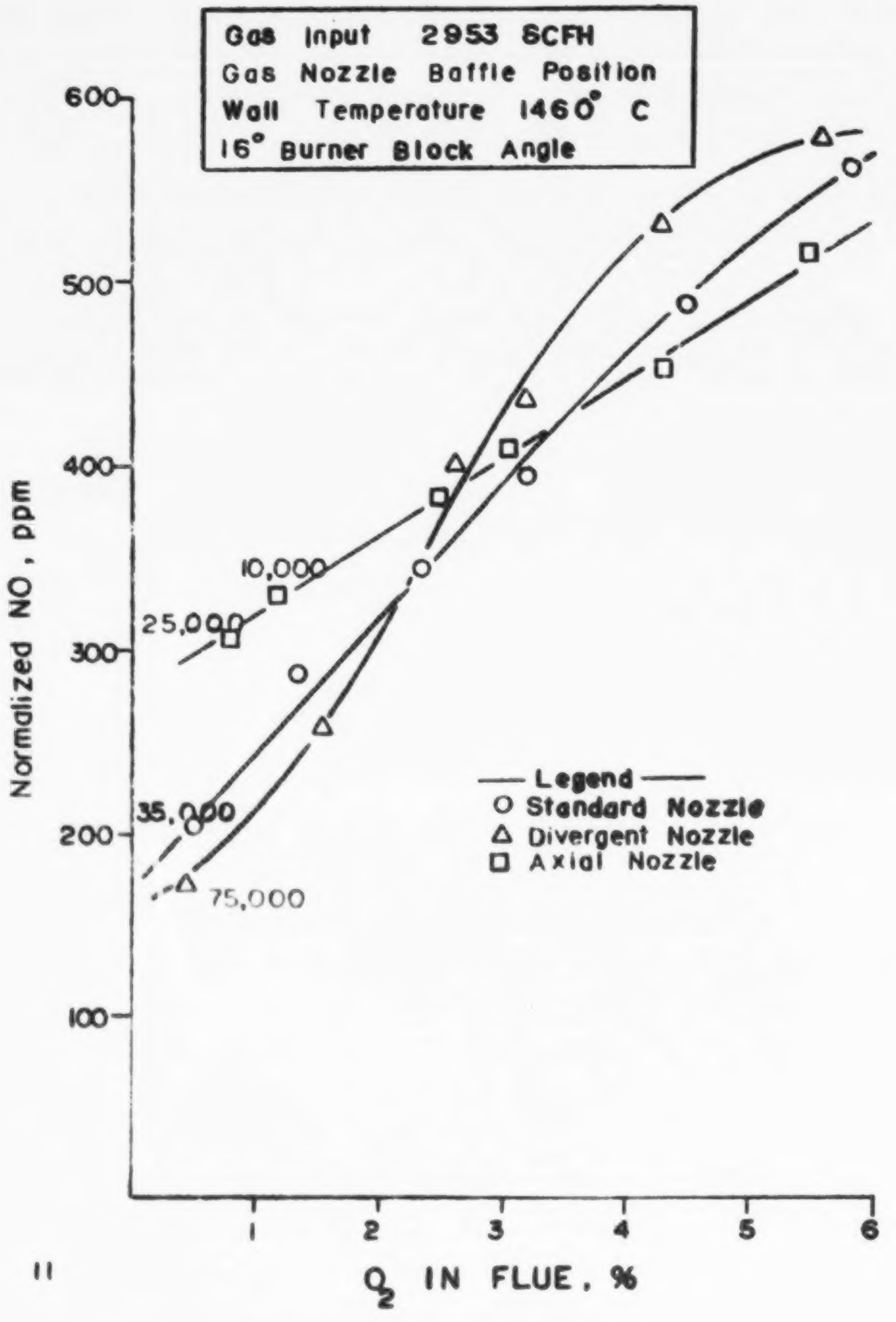


Figure 21. Normalized NO concentration as a function of flue O_2 for the SF LB burner with standard, divergent, and axial gas nozzles

air. There is no one general interaction theory that explains these curves in their entirety. Therefore, we selected a 1% level of excess O_2 for analysis. This level was chosen because it consistently produced the lowest levels of NO, with concentrations below 50 ppm.

Table 2 lists the nozzle type as a function of burner-block angle for both the SFLB and the IFLB. The inlet gas velocity is listed in parenthesis beside the nozzle type. For 14% excess air, the velocity is 120 ft/s. Note that the air velocity increases with increasing excess air. The arrows indicate the direction of increasing NO concentration. We know from flame-length observations that the standard and divergent nozzles have similar rates of mass exchange between flow zones, whereas the axial nozzle has a slower exchange rate. It is not surprising that the standard and divergent nozzle show similar trends in NO formation as a function of burner-block angle. For the IFLB, the NO concentration increases with burner-block angle; for the SFLB, it decreases with an increasing angle.

Table 2. NORMALIZED NO CONCENTRATION AT 1% EXCESS O_2 WITH AN AIR PREHEAT TEMPERATURE OF 460°C AS A FUNCTION OF BAFFLE TYPE, GAS NOZZLE TYPE, AND BURNER-BLOCK ANGLE

	NO Concentrations				
	IFLB			SFLB	
	Block Angle, deg				
	4	8	16	8	16
Nozzle Type	ppm				
Radial (1043 ft/s)	--	--	--	950	--
Radial (532 ft/s)	590	--	--	700	--
Standard (38 ft/s)	375 →	400 →	470	490 ←	240
Divergent (654 ft/s)	175 →	200 →	235	440 ←	210
Axial (611 ft/s)	215 ←	175 →	200	230 →	310
Standard, 15% FGR	120	--	--	110	--

For the IFLB, we increased the mixing rate between the primary and secondary jets more than the size, shape, and mixing rate of the primary recirculation zone with the primary and secondary jets. For the SFLB, we were successful in improving the mass exchange between the primary recirculation zone and the primary and secondary jets, which resulted in approximately a 55% reduction in NO emissions. The high-velocity axial nozzle showed almost the opposite effect. For the SFLB, there was a 30% increase in the emission level as the block angle was increased. Thus, for high swirl intensity and high axial velocity, increasing the burner-block angle resulted in a larger primary-secondary jet mass exchange. We investigated the IFLB with the 16-deg block for flow separation between the secondary jet and the block and obtained negative results. Therefore, we assumed that it also was not present for the SFLB and the 16-deg block. The results for the IFLB and the high-velocity axial nozzle were somewhat mixed. There was a decrease in the NO level with a block angle increase from 4 to 8 deg followed by an increase in the NO level with an angle increase from 8 to 16 deg. The optimum burner-block angle for producing minimum NO emissions with the axial nozzle was approximately 10 deg.

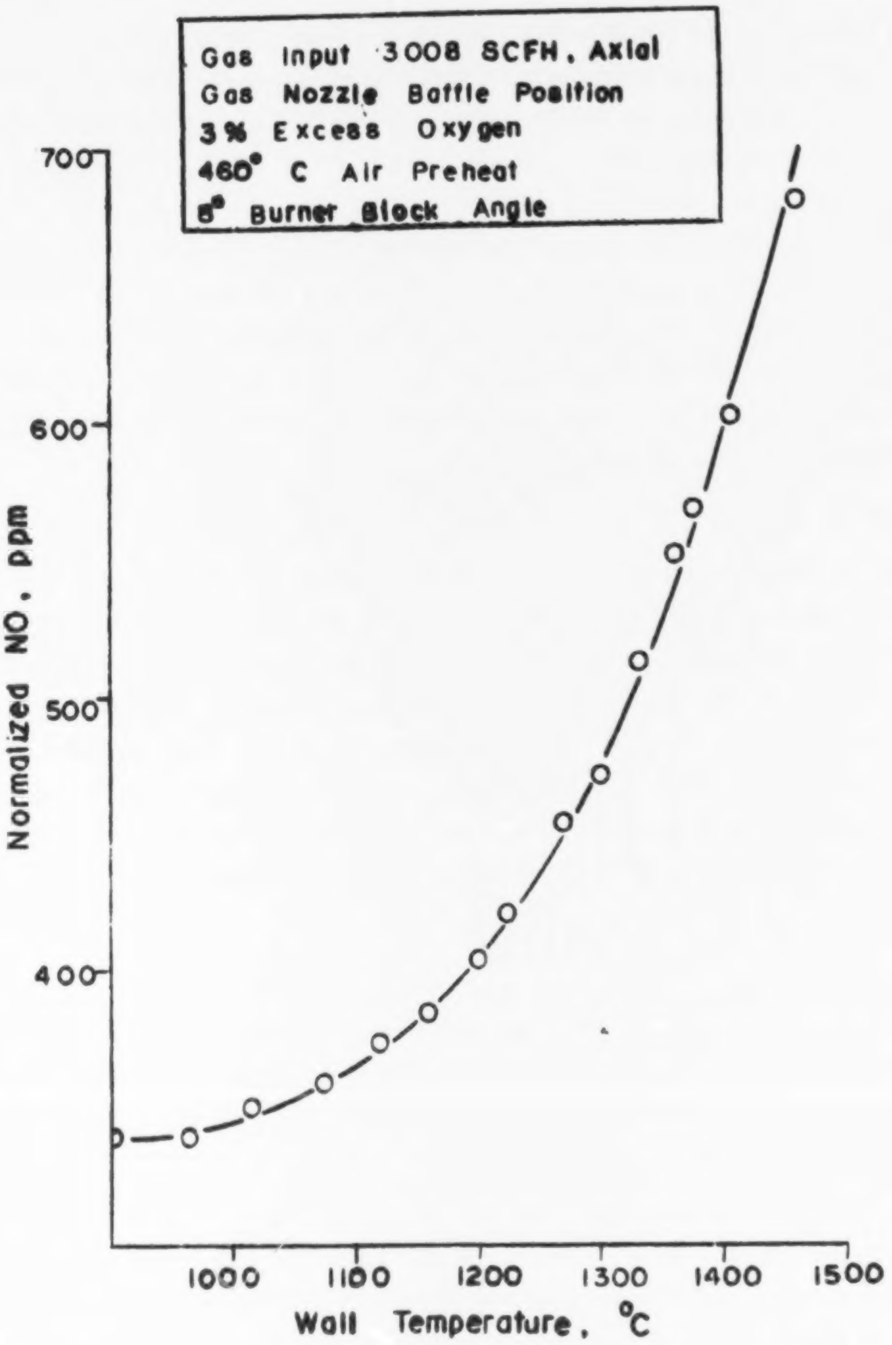
Wall Temperature

Because of the observed sensitivity of wall temperature to the flue concentrations of NO during these tests, we decided to gather data relating NO to wall temperature during a warm-up cycle. The standard nozzle was fired with 3000 SCF/hr of gas at 3% excess O_2, 460°C air preheat, and the SFLB. The results are graphed in Figure 22. The dramatic increase in the level of NO emissions above 1300°C indicates that an accurate control of wall temperature is required to produce a self-consistent set of experimental data. It also confirms that the furnace should be operated with as low a wall temperature as possible.

Furnace Geometry

The IFLB burner was mounted on our cylindrical (tunnel) test furnace, which has a cross-sectional area of 1.17 sq m (12.6 sq ft) and a volume of 6.4 cu m (226 cu ft). The following operating parameters were investigated: secondary combustion air preheat, method of gas injection, and position of gas injector.

Figure 23 shows the emissions data collected from the IFLB with the standard gas injector (2-inch stainless-steel tube), a 2000 SCF/hr gas input, and nonpreheated and preheated secondary combustion air. To determine the influence of furnace geometry on NO emissions, Figure 23 compares these data with similar data collected during a test on the larger-diameter furnace. The cross-sectional area of this rectangular furnace is 2.3 sq m (25 sq ft) and the volume is 10.6 cu m (375 sq ft). With the exception of



13

Figure 22. Normalized NO concentration as a function of wall temperature for the SF LB burner with a standard gas nozzle

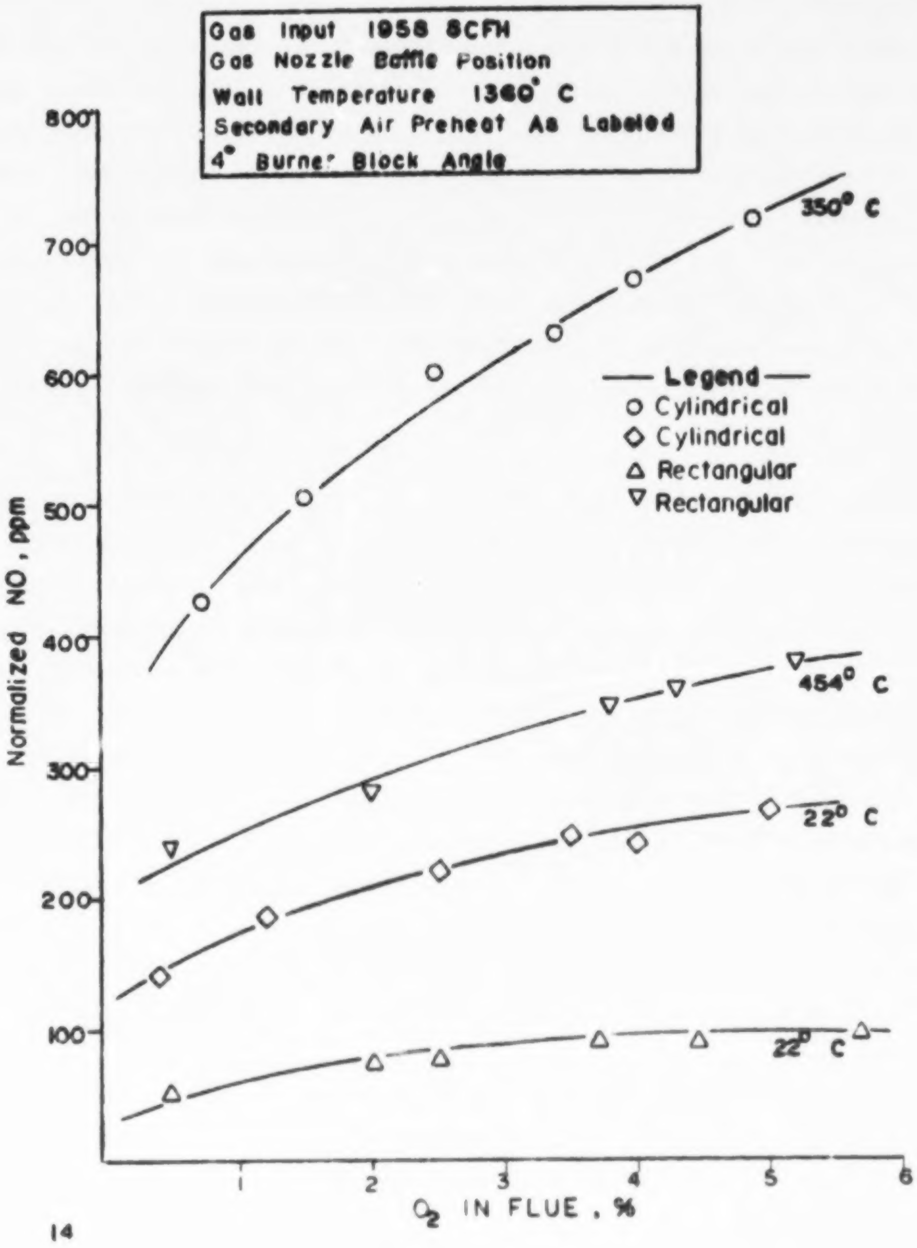


Figure 23. Normalized NO concentration as a function of flue O_2 for the IF LB burner with a low-velocity gas nozzle

secondary air preheat temperature (350°C for the cylindrical furnace, compared with 454°C for the rectangular furnace), all other burner and furnace operating conditions (gas input, gas nozzle position, burner-block angle, and wall temperature) were identical. For both conditions of secondary air preheat, the cylindrical furnace had the higher levels of emissions. The area ratio between the burner-block opening and the burner wall is 35.9 for the rectangular furnace and 18.2 for the cylindrical furnace. These ratios reflect the relative sizes of the secondary recirculation zones. The primary reason for the difference in measured NO concentrations between the two combustion chambers is the unequal secondary recirculation zone volume.

Nozzle Type

Additional tests were conducted to investigate the influence of gas injection on total NO emissions. In these trials, we used a high-velocity (127 m/s, 407 ft/s) gas nozzle and a divergent gas nozzle (injection velocity 135 m/s, 436 ft/s). Both injectors have only an axial velocity component. Figure 24 compares the normalized NO emissions as a function of excess O_2 from these gas nozzles. The low-velocity nozzle produces less NO, by a factor of 2, than the high-velocity nozzle. This result contradicts the data collected from the rectangular furnace, which are presented in Figure 25. Although the rectangular furnace has a higher gas input (2998 SCF/hr) and a higher secondary air temperature (450°C), the cylindrical furnace had the higher emission levels for a given gas nozzle. This occurs because NO production in gas flames is entirely thermal in origin. Thus, any change in the combustion chamber or fuel-air mixing that results in lower peak and average flame temperatures reduces the rate of NO production. Conditions that should reduce NO emissions include decreasing the rate of heat release, increasing the mass exchange between the flame zone and secondary recirculation zone, and reducing the wall temperature.

During previous trials with the rectangular furnace, the high-velocity gas nozzle always produced less NO emissions than nozzles with lower injection velocities. This result was explained by the different fuel-air mixing rates. An increase in injection velocity was achieved by decreasing the cross-sectional area of the injector, which caused a decrease in the fuel-air mixing rate and permitted an increase in recirculation and combustion zone mass exchange. The combustion zone is blended with combustion products, which

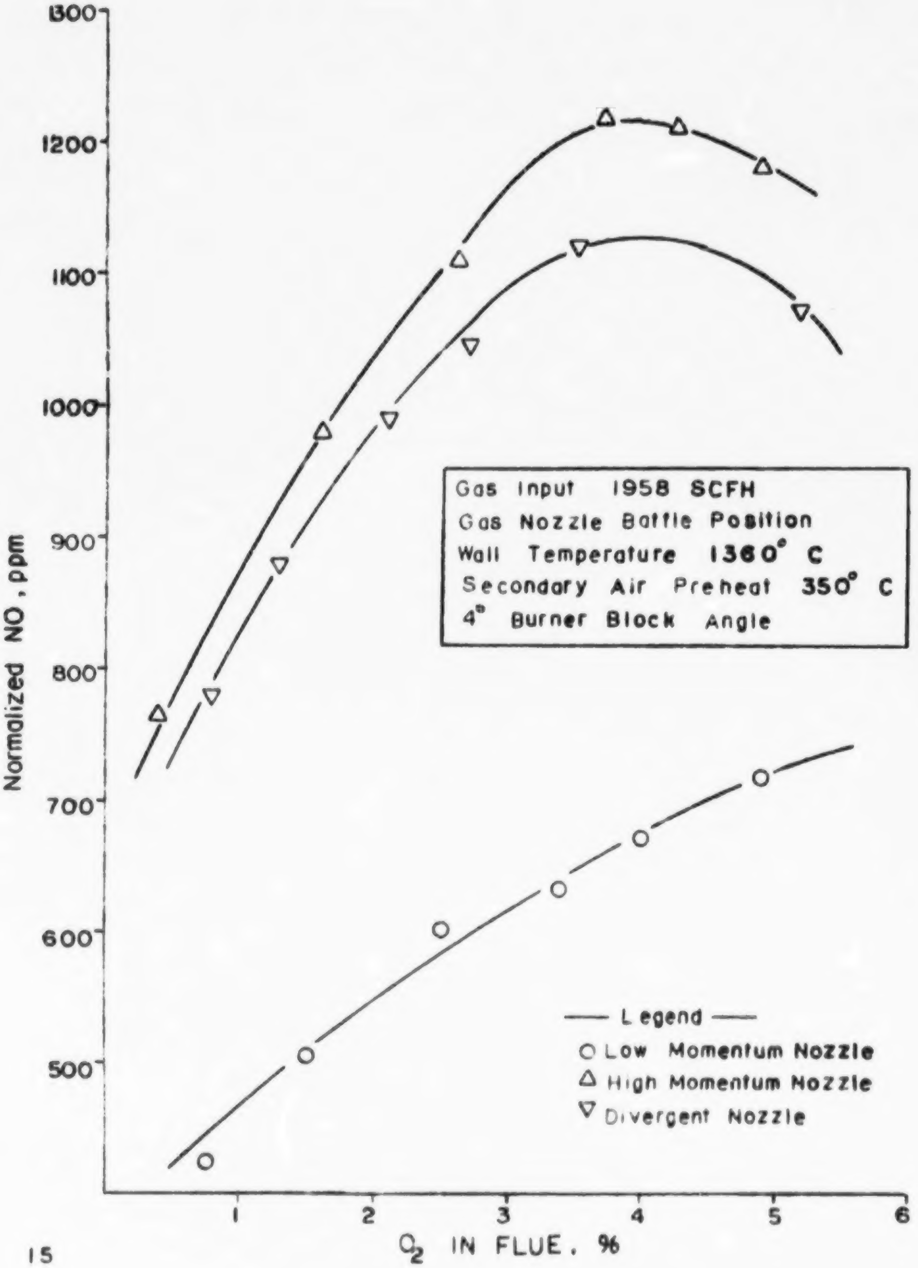


Figure 24. Normalized NO concentration as a function of flue O_2 for the IF LB burner with low-velocity, high-velocity, and divergent gas nozzles

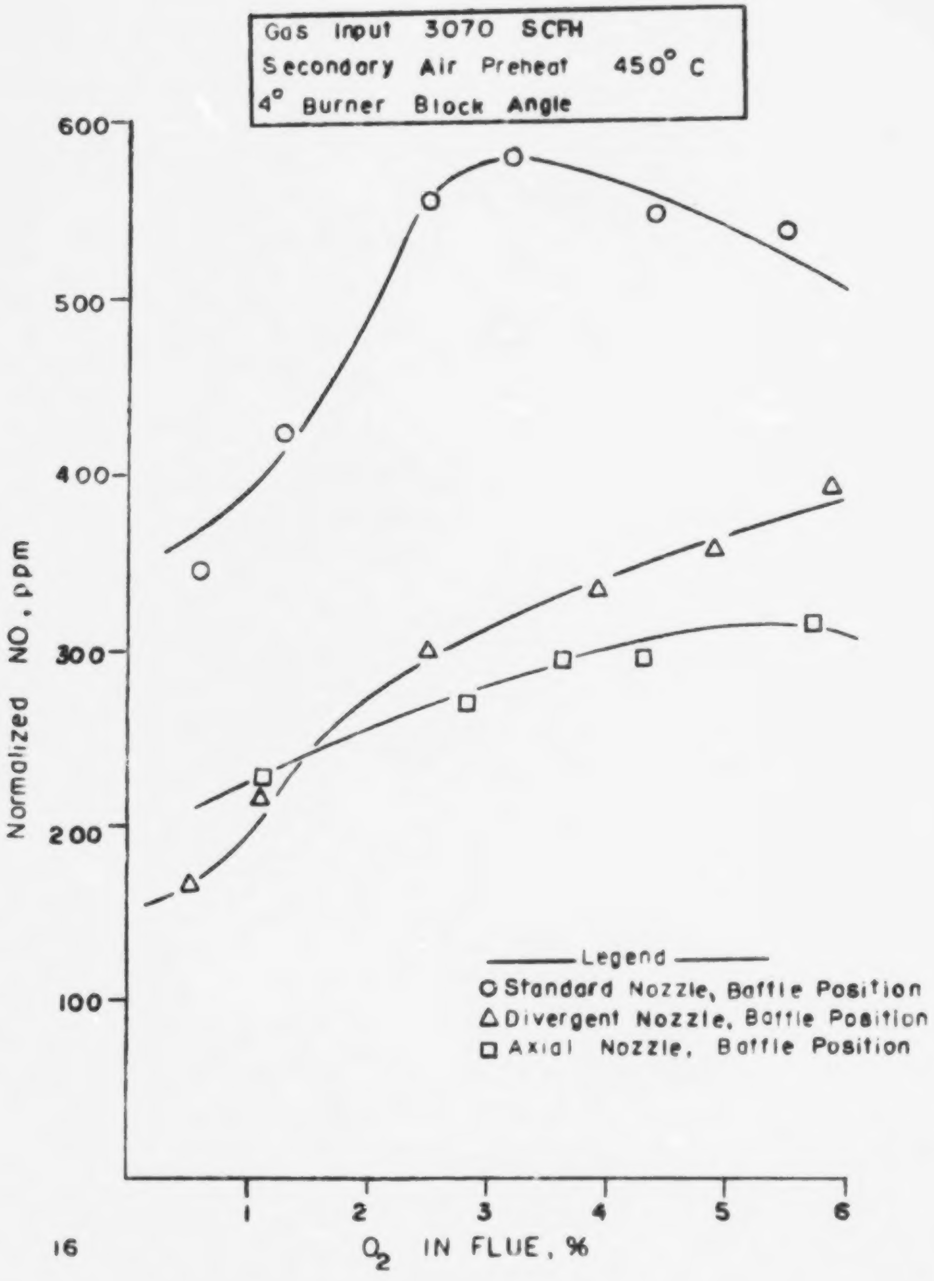


Figure 25. Normalized NO concentrations as a function of flue O_2 for the IF LB burner with standard, divergent, and axial gas nozzles

result in lower flame temperatures. However, for the cylindrical furnace, the high-velocity gas nozzle causes higher NO emissions. This means that even though the same method of gas injection was used in each furnace, the thermal history of the two flames was different. The major reason for a higher flame temperature in the cylindrical furnace would be a smaller mass exchange between the secondary recirculation and the combustion zones. The smaller mass exchange occurred because of a decrease in the size of the secondary recirculation zones, which, in turn, resulted from a smaller combustor cross-sectional area.

The divergent nozzle injects the gas radially at a 45-deg angle to the burner axis. Comparison of Figures 24 and 25 shows that the cylindrical furnace has the higher levels of emissions for the divergent nozzle. Arguments similar to those presented for high-velocity nozzle could also be made for the divergent nozzle. However, for both combustion chambers, the divergent nozzle has lower emissions than the high-velocity nozzle. The diverging gas injection causes a primary recirculation zone, which allows a larger dilution of the combustion zone with combustion products than an axial injector. This increased dilution leads to lower flame temperatures and reduced emissions.

Natural-Gas, Low-NO_x Burner I

IGT has been commissioned by three gas utilities (Consumer's Gas Co., Consolidated Natural Gas Co., and Southern California Gas Co.) to develop a burner with low NO_x emission levels relative to the industrial burner it was intended to replace and with a similar flame geometry and luminosity. The initial design guidelines for this burner development work were extracted from the data presented in this paper. After fabrication, the low-NO_x burner I (LNO-1) was mounted on the cylindrical furnace for NO_x emission level testing.

Standard Operating Conditions

The initial set of trials was conducted by using 25% primary air. This percentage is determined by ratioing the volume of primary air to total air needed for stoichiometric combustion and multiplying it by 100. Figure 26 shows the results of these tests as normalized NO plotted against excess O_2. These data were collected by premixing the primary air and fuel, which gives

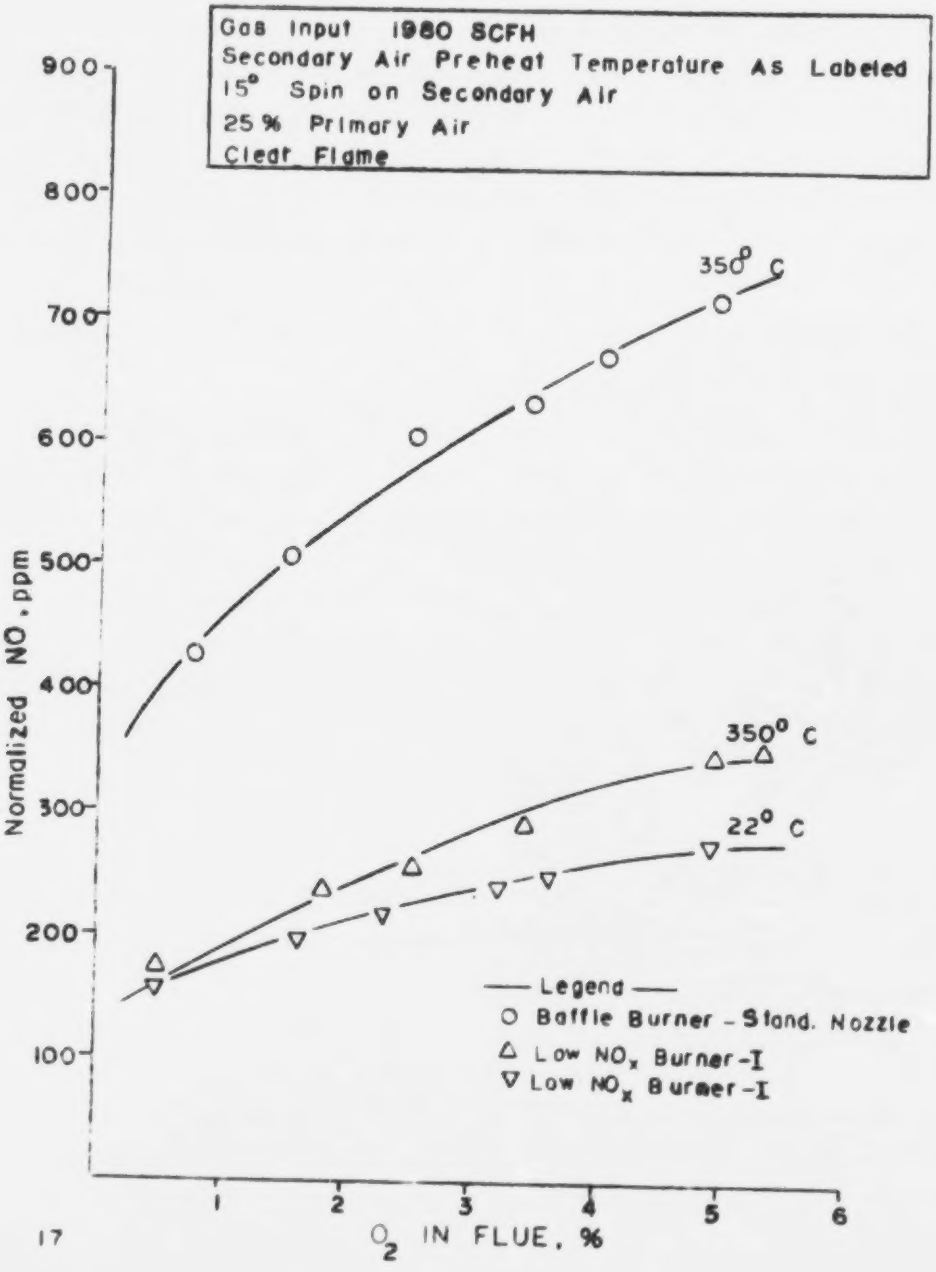


Figure 26. Normalized NO concentrations as a function of flue O_2 with 25% primary air

rise to a clear flame. For comparison, Figure 26 also shows the emissions curve for the IFLB burner with a standard nozzle. The LNO-I burner was designed to replace burners in the IFLB burner category. Comparison of the emission levels of these burners at 350°C secondary air preheat shows that the LNO-I burner was extremely effective in reducing NO emissions. At a 2% level of excess O_2 (approximately 10% excess air), the LNO-I burner emitted 55% less normalized NO than the IFLB burner. This decrease in NO emissions dropped to 18% for NO secondary air preheat.

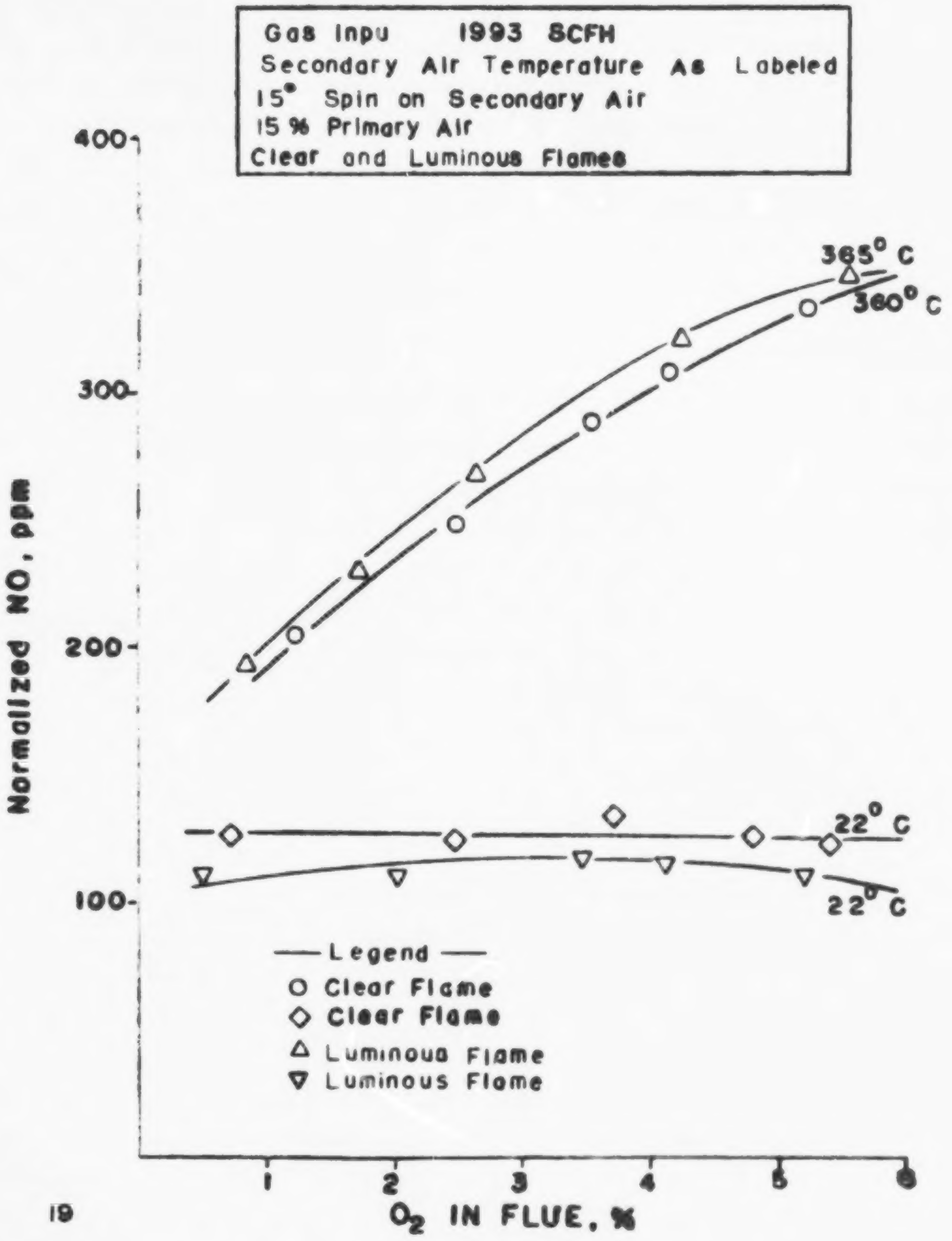
Flame Luminosity Adjustment

Adjusting the primary air and fuel so that no mechanically induced premixing occurred prior to ignition (luminous flame) did little to alter the LNO-I burner emissions without secondary air preheat. Figure 27 illustrates the normalized NO emissions versus excess O_2 for luminous flame operating conditions. With a 350°C secondary air temperature, the luminous flame had an NO level, at 2% excess O_2, 13% lower than that of the clear flame. Thus, the effect of the mixing rate of primary air and fuel on NO emissions is directly related to secondary air temperature. At ambient combustion air temperatures, the luminous and clear flames had nearly the same emission levels, but at the elevated (350°C) combustion air temperature, the clear flame had the higher emissions.

Variation in Primary Air

To determine the influence of primary air volume on NO formation, the amount of primary air was reduced to 15%. Figure 28 shows the normalized NO-versus-excess O_2 relationships determined for this primary air volume. The clear flame with 350°C secondary air preheat displayed little change in NO emissions between 15% and 25% primary air. The luminous flame was somewhat more sensitive to primary air volume, yielding a 10% increase in the NO emission levels at the lower primary air level. Thus, if a luminous flame is needed for the desired industrial application, the higher the percentage of primary air, the lower the NO emissions.

With an ambient secondary air temperature, both flame conditions produced the lowest levels of NO measured during the burner trial series, indicating that the percentage of primary air should be reduced as the secondary air preheat temperature is decreased. To completely generalize the



19

Figure 27. Normalized NO concentration as a function of flue O_2 for the LNO-1 burner under luminous-flame operating conditions

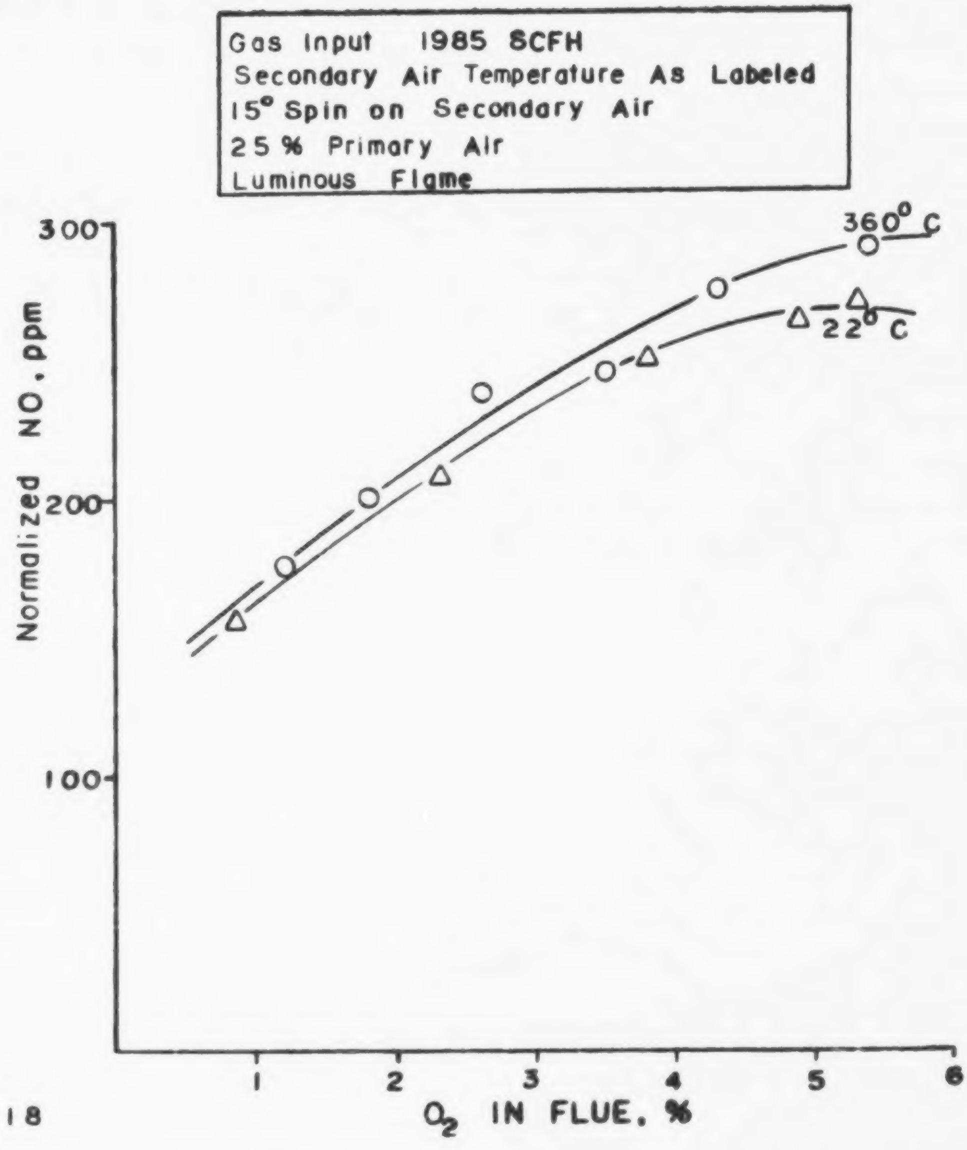


Figure 28. Normalized NO concentration as a function of flue O_2 for the LNO-1 burner with 15% primary air

dependence of NO emissions on primary air volume would require testing above 25% primary air; however, because of primary fan capacity, these trials were not possible.

Although this investigation was very successful in demonstrating that the LNO-I burner has low NO emission characteristics, particularly at elevated secondary air temperatures, additional testing is under way to simplify the burner design and to determine the burner's limitation, not only in NO_x reduction but also in the types of flames it is capable of producing.

FUTURE WORK

The final step of the program has been initiated by the American Gas Association in its funding of a field test demonstration for the LNO-I burners. IGT is currently contacting industries that might be interested in having LNO-I burners mounted on their furnaces with IGT furnishing the burners and monitoring the emissions during process operation.

SUMMARY

This experimental research program has demonstrated that the NO emission levels from gas-fired industrial burners can be significantly reduced by alterations in the combustion aerodynamics. A synopsis of the operational variables studied and their test results is presented in Table 3. The technique resulting in the most dramatic reductions of NO emission levels was external flue-gas recirculation. This verified the intimate relationship between flame temperature and NO emissions; thus, this program's efforts concentrated on reducing flame temperature either by reducing the rate of combustion or by diluting the flame with combustion products recirculated within the furnace using combustion aerodynamics.

Although large variations in NO emissions occur because of changes in the amount of excess air, reduction levels can be established in addition to their relative effectiveness by comparing the emission levels at several fixed levels of excess air. The conclusions reached below are based on an excess air level equivalent to 3% oxygen in the flue and a combustion air preheat temperature of 450°C.

Table 3. SYNOPSIS OF DATA COLLECTED FOR THE BAFFLE BURNER

Excess Oxygen, %	1	3
Normalized NO, ppm		
IFLB Burner (Standard operating conditions: gas input, 3000 SCF/hr; 450°C, secondary air preheat; 2-inch-diameter axial fuel injector; baffle fuel injector; baffle position; and a 1400°C wall temperature, 4-degree burner block.)		
Standard Operation	390	580
Gas Input, 2000 SCF/hr	250	310
Secondary Air Temperature: 225°C	195	235
22°C	110	125
Wall Temperature, 1100°C	225	260
EFGR 15%	130	180
EFGR 30%	40	60
Radial Nozzle-Throat Position	200	260
Axial Nozzle-Throat Position	110	190
Throat Position	280	390
Divergent Nozzle	190	300
Axial Nozzle	210	250
8-Degree Burner Block (B. B.)	410	560
8-Degree B. B. - Axial Nozzle	200	230
8-Degree B. B. - Divergent Nozzle	220	350
SFLB Burner (Standard operating conditions: gas input, 3000 SCF/hr; 450°C, secondary air temperature; 2-inch-diameter axial fuel nozzle; baffle position; 8-degree burner block angle; and 1400°C average wall temperature.)		
Standard Operation	450	660
Gas Input, 2000 SCF/hr	270	430
Secondary Air Velocity, 125 ft/s*	210	250
Secondary Air Temperature: 225°C	165	270
22°C	95	160
Wall Temperature, 1000°C	270	320
EFGR 15%	100	150
EFGR 30%	60	80
Radial Nozzle	660	800
Divergent Nozzle	440	580
Axial Nozzle	210	390
16-Degree Burner Block (B. B.)	210	380
16-Degree B. B. - Divergent Nozzle	180	400
16-Degree B. B. - Axial Nozzle	300	390
– Cylindrical Furnace –		
IFLB Burner (Standard operating conditions: gas input, 2000 SCF/hr, 350°C, secondary air temperature; 2-inch diameter axial fuel nozzle, baffle position, 4-degree burner block angle and 1100°C average wall temperature.)		
Standard Operation	460	610
Axial Nozzle	880	1170
Divergent Nozzle	825	1090
LNOX-I	180	280

* Gas input for this test was 2000 SCF/hr

For the intermediate flame length baffle burner (IFLB), which has a tangential-to-axial velocity component ratio of 0.27, we found the following:

a. Reducing the firing rate from 3000 SCF/hr to 2000 SCF/hr resulted in a 47% reduction in NO emissions.

b. Reducing the combustion air preheat from 450°C to 225°C leads to a 59% reduction in NO emissions, and no preheat gives a 78% reduction.

c. By cooling the walls from 1400°C to 1100°C, the NO emissions diminished by 55%.

d. External flue-gas recirculation reduced NO emissions by 69% for 15% recirculation and 90% for 30% recirculation.

e. Several types of fuel injectors and positions were tested with a maximum reduction of 67% measured for the high-momentum axial nozzle in the throat position. The minimum changes in flame geometry and luminosity were observed for the divergent nozzle, which showed a 48% decrease in NO emissions.

f. The burner block angle was increased from 4-degrees to 8-degrees, leading to only a 4% reduction under standard burner operating conditions. However, by also changing the method of fuel injection a maximum reduction of 60% was measured with the high-momentum axial gas nozzle.

For the short flame length baffle burner (SFLB), which has a tangential-to-axial velocity component ratio of 0.47, we observed the following:

a. Reducing the firing rate from 3000 SCF/hr to 2000 SCF/hr resulted in a 35% decrease in NO emissions.

b. With a 2000 SCF/hr gas input, the combustion air velocity was increased from 80 ft/s to 125 ft/s, which diminished the NO emissions by 42%.

c. Reducing the combustion air temperature from 450°C to 225°C resulted in a 59% NO reduction and, with no preheat, a 76% reduction.

d. Decreasing the wall temperature from 1400°C to 1000°C reduced the NO emissions by 52%.

e. Externally recirculating flue gas and blending it with the combustion air produced a 77% decrease in emissions for 15% recirculation and 89% reduction for 30% recirculation.

f. Of the several types of fuel injectors tested, the high-momentum axial nozzle produced the minimum emissions with a 41% reduction.

g. The burner block angle was increased from 8-degrees to 16-degrees. This produced a 41% decrease in NO emissions for all gas nozzles tested.

The IFLB burner was tested on our cylindrical test furnace, which has a volume of 226 cu ft and an area ratio between the burner block opening and the burner wall of 18.2 compared with a 35.9 ratio for the rectangular furnace. During these trials we have the following observations:

a. At a 2000 SCF/hr firing ratio, the cylindrical furnace emissions were 97% greater than the emissions from the rectangular furnaces.

b. The high-momentum axial and the divergent nozzles produced increases in the NO emissions of 92% and 79%, respectively, although both produced reductions in NO emissions on the rectangular furnace.

This program has led to the design, development, and testing of a low-NO-emissions burner (LNOX-I), which, hopefully because of its versatile design, could be used in a large number of industrial applications. The following conclusion was drawn from the test data accumulated from LNOX-I:

- With 2000 SCF/hr firing ratio on the cylindrical furnace, the LNOX-I burner resulted in a 54% reduction in NO emissions when compared with the IFLB burner under similar operating conditions.

Thus, this program has not only demonstrated techniques and variations in furnace and burner operating conditions, which lead to reduced NO emissions, but these test results have produced a burner design that has characteristic low emissions. The final success of this program will be in the near future when the LNOX-I burner is field-tested.

INTEGRATED LOW-EMISSION
RESIDENTIAL FURNACE

By:

L. P. Combs, W. H. Nurick, and A. S. Okuda

Rockwell International, Rocketdyne Division

Canoga Park, California

Preceding page blank

ABSTRACT

Analytical and experimental studies are establishing practical technology for simultaneously minimizing pollutant emissions from and improving fuel economy of oil furnaces for residential space heating. Objectives are to reduce the emission of nitrogen oxides from current levels of 2-1/2 to 3 g/kg of fuel burned to less than 0.5 g/kg, and to raise season-averaged thermal efficiency by at least 10 percent above that achieved by typical current conventional furnaces, while maintaining minimum emissions of smoke, unburned hydrocarbons, and carbon monoxide.

The approach has involved research on designing conventional pressure-atomizing oil burners for low emissions, matching furnace fireboxes to such low-emission burners, and operating these optimized components under fuel-conservation conditions. This paper summarizes the research results and shows how they are being applied in the design, assembly, and test of a prototype warm-air furnace to verify that the technology can be used in practical, cost-competitive production furnaces.

ACKNOWLEDGEMENT

Work upon which this presentation is based, was performed pursuant to Contract Nos. 68-02-0017 and 68-02-1819 with the U.S. Environmental Protection Agency. The EPA Contract Officer was Mr. G. Blair Martin, Combustion Research Section, Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina.

INTRODUCTION

The Environmental Protection Agency has sponsored studies over the past few years to document the emission of air pollutants from existing residential and commercial oil-fired space heating equipment (Ref. 1 and 2). Concurrently, the EPA has also supported applied research programs to determine the effects of design and operating parameters on exhaust gas emission levels and to devise strategies for minimizing pollutant emissions (e.g., Ref. 3, 4, and 5). These and related studies have shown that substantial reductions in total emissions from furnaces can be realized by applying combustion control technology, such as flue gas recirculation, staged combustion, and advanced burner designs.

As part of those EPA activities, Rocketdyne performed an intensive investigation of residential and commercial oil burners (Ref. 5) which led to criteria for optimizing conventional burner designs with respect to emissions. The optimized burners were shown to be capable of reducing NO_x emissions to below 1 g NO/kg fuel, in contrast to typical manufactured residential burners that operate at about 1 1/2 to 3 g NO/kg fuel or higher. During the investigation of burner optimization, several variations in the combustion chamber construction (adiabatic refractory walls vs metal heat-sink or water-cooled walls) and design (relative orientation of the burner and chamber axes and relative burner and chamber diameters) were also studied. The results clearly demonstrated that the total emissions are sensitive to (1) the design of various components comprising a residential heating system and (2) design interactions among the components. It became obvious, therefore, that minimum emissions could be achieved only by systematically optimizing the burner in conjunction with the furnace combustion chamber and heat exchanger as well as operating mode. The research described in this paper was undertaken to investigate such system optimization and to delineate furnace design requirements for commercializing the optimum furnace technology.

In view of uncertainties in fossil fuel supplies and prices, and of the national emphasis on achieving energy independence, an optimized furnace should, in addition to providing low levels of pollutant emissions, also provide some substantial increase in overall thermal efficiency. Further, for the developed technology to be adopted commercially, the optimized design must be cost-competitive. In this regard, significantly increased fuel economy will be important in allowing consumer recovery, within a reasonable number of heating seasons, of any increased capital costs that might result from modifications required for system optimization. The need to establish technological requirements for optimizing residential heating systems is important, therefore, because such effort addresses both the improvement of air quality and a better utilization of the nation's dwindling energy resources.

The principal objective of this research program was to establish the technology required for engineering optimization of residential heating furnaces combining minimum pollutant emissions with maximum thermal efficiency. Primary emphasis was given to systems fueled with No. 2 distillate fuel oil. General overall goals are: (1) to reduce nitrogen oxide emissions to less than 0.5 g NO/kg fuel burned, while maintaining minimum emissions of CO, UHC, and smoke, and (2) to increase overall season-averaged furnace energy efficiencies by 10 percent or more above those achieved by current conventional systems.

BACKGROUND

Typical residential oil furnace emission and efficiency performance data are summarized in Table 1 for the existing furnace population and for new furnaces representative of current technology.

Cycle-averaged emissions data, abstracted from Ref. 1 and 4, show that the products of incomplete combustion (smoke, CO, unburned hydrocarbons, and particulates) are generally quite low for both the existing population and current new furnaces, although on the average those from the former set tend to be appreciably higher. The low levels result from achieving the consistent design goal of accomplishing complete combustion while the higher levels for the existing population are not surprising, considering the greater component ages and broad diversity of burner types, firebox design, conversion units, etc., which make up that population.

Average emissions of the oxides of nitrogen from current new furnaces are approximately the same as the average from the existing population. This results from the preponderant use of side-fired, refractory-lined fireboxes, irrespective of the burner designs.

Wide ranges of thermal efficiency estimates for the existing residential furnace population may be found in the technical literature. Those listed in Table 1 are representative of the mid-range, and are generally consistent with the flue gas CO_2 concentrations (or excess air levels) reported in Ref. 1 and 4. Recognizing that gross efficiencies, based on the higher heating value of the fuel, are about 5 to 7 percent lower than net efficiencies, it may be estimated that fuel utilization efficiencies potentially might be increased by as much as 35 to 40 percent. Achieving such large gains, however, would entail very significant departures from current design concepts, and manufacturing, marketing, and utilization practices. To maximize efficiency, considerably larger heat exchangers would be needed to cool flue gases to near-room temperature and condense their combustion-generated water vapor. A number of problems would immediately arise, e.g., inadequate firebox draft, need for corrosion-resistant furnace and flue construction materials, condensate disposal and noncompetitive initial costs. For these reasons, it was deemed appropriate for the current research to address efficiency gains achievable by less drastic modifications of existing commercial technology, i.e., improvements that can be achieved relatively near term and remain cost-competitive in the marketplace.

IMPROVING THERMAL EFFICIENCY

The greatest source of thermal inefficiency in residential space heating equipment is the convection of heat up the flue. When the burner is being fired, exhausted product gases carry off substantial sensible heat and the heat of vaporization of combustion-generated water vapor. Flue gas sensible heat losses may be reduced by lowering either excess air or flue gas temperatures. Steady-state net thermal efficiencies might thus be increased by 5 to 10 percent before furnace operation is constrained by pollutant formation, low draft, and condensation problems. During this same time, most installations use heated, humidified living-space air for burner combustion air and for barometric draft control air. Although the resultant heat losses are not charged against furnace thermal efficiency, fuel utilization efficiency can be raised by 10 percent or more by using a sealed air system to bring in outdoor ambient air for these uses.

When the burner is not being fired, a natural draft flow of air through the burner, firebox, etc., cools furnace components and continues to convect heat up the flue. This loss can reduce net thermal efficiency by as much as 5 percent and is a major fraction of the transient heat losses which cause cycle-averaged efficiencies to be lower than steady state. The lower the draft air loss is, the less sensitive is cycle-averaged efficiency to variations of cycle duration and of fractional burner-on time. Draft air loss can be eliminated by providing a positive shutoff device in the combustion air supply. It can also be reduced or eliminated by having the burner fire more nearly continuous, e.g., by using modulated flow or high/low/off burner control. No real thermal efficiency advantage can be realized with such control schemes, however, because the flue gas temperature varies enough to offset the reduction or elimination of draft air heat losses.

Heat conducted to the exterior cabinet of a furnace is radiated and convected to the surroundings. Although treated as a furnace loss, this heat, in some installations, may contribute directly to heating the residence and not be a true heat loss. These furnace setting losses average about 1-1/2 to 2 percent for warm-air furnaces. They are higher (3 to 3-1/2 percent) for hydronic boilers, because component temperatures are more nearly constant during standby than are those in warm-air units. Reduction of these losses nominally depends upon a straightforward economic tradeoff of fuel economy vs more expensive insulation, although manufacturers must also be concerned about first-cost competition.

The electrical energy expended in operating furnaces amounts to no more than 2 to 3 percent of the net heat of combustion of the fuel. Nevertheless, the minimizing of electric power consumption is a worthwhile goal because of its greater cost to the homeowner than fuel oil and because of the factor of 2 1/2 to 3 on total energy savings when the inefficiency of the electric generating plant is considered.

To maximize furnace thermal efficiency, without departing substantially from current manufacturing and installation practices, it was concluded that the following measures should be effected:

1. Design the burner/combustion chamber combination to operate pollution-free at low excess air levels, e.g., 10 to 15 percent excess air (13 1/2 to 13 percent CO_2)
2. Lower flue gas temperatures as much as possible. The minimum practical temperature is probably around 200 C (392 F)
3. Employ sealed air systems for combustion air and barometric control. Filter the combustion air to prevent long-term degradation of performance
4. Close the combustion air supply during standby
5. Effect savings in electrical power consumption. Areas to consider are proper matching of drive motors to air fans and fuel pumps, interrupted-spark rather than continuous-spark ignition systems, and solid-state ignition and control circuits.

REDUCING POLLUTANT EMISSIONS

When clean fuels, such as natural gas and No. 2 fuel oil, are burned in residential space heating equipment, two classes of combustion-generated air pollutants are emitted, viz., incomplete combustion products (CO, UHC, and smoke) and oxides of nitrogen. The two classes are similar in some respects; their concentrations in the flue gases are usually very low, so that their production does not affect significantly combustor performance or thermal efficiency, and their concentrations usually are not particularly close to those representative of thermal equilibrium, but are more likely to be determined by poorly controlled features of combustion, e.g., regions of poor mixing, spray/combustor wall interactions, size and strength of recirculation eddies, and flame-zone cooling phenomena. These characteristics tend to obviate quantitative analytical characterization of the pollutant emissions; as a result, such characterizations are usually studied experimentally. Conversely, the two classes are dissimilar in some respects, principally because their usual concentrations lie on opposite sides of equilibrium. Thus, for example, NO production is enhanced by higher temperatures and longer flame-zone residence times, both of which tend to drive the hydrocarbon combustion processes to completion and reduce carbonaceous emissions.

It was reasonably well established in the earlier oil burner studies (Ref. 5) that an optimized conventional burner can operate reliably at low excess air levels and produce acceptably low CO, UHC, and smoke. Its NO emission levels, however, were a factor of 2 or more higher than the target reduction below 0.5 g NO/kg fuel, and it was uncertain whether that goal could be reached by the optimizing of the furnace combustion chamber for this burner.

Therefore, the experimental investigation, which used research combustion chambers rather than typical furnaces, consisted of three separate, but related parts. One part dealt exclusively with the 1 ml/s (gph)* conventional burner, optimized to produce low emissions, as described in Ref. 5. This effort sought to optimize the matching of the fire box (combustion chamber) to that fixed-burner design. The other two parts branched out to burners having, in one case, forced flue gas recirculation (FGR) to the burner air intake and, in the other case, forced combustion gas recirculation (CGR) from the combustion chamber to the burner air intake. These efforts were also focused upon the optimizing of the burner/firebox combination for low emissions.

The first of these approaches--the optimizing of the combustion chamber matched to the optimum low-emission burner--was found to be the best approach. The experimental investigation with the 1 ml/s combustion gas recirculation (CGR) burner was frustrated by an inability to simultaneously satisfy the NO, CO, and UHC emission goals. Because of these problems and the inherent potential problems of moderately high temperature mixed gases being passed through the combustion air fan, it was concluded that further work with this burner concept was not warranted.

---

*1.00 ml/s = 0.951 gph. The 5-percent difference is neglected in this paper when reference is made to burner firing rates.

Tests of the 1 ml/s flue gas recirculation (FGR) burner were more successful and showed good potential for satisfying the emission goals under efficient operating conditions. However, the actual achieving of all the emission goals would probably be contingent upon the use of more-complicated burner start sequence to eliminate start-spike emissions of CO, smoke, and UHC which were experienced under conditions having acceptably low NO.

Thus, it was concluded that the optimized conventional burner in optimized combustion chambers is a preferred choice over both the CGR and the FGR burners. With this choice, the emission goals can be met, low-excess air levels can be employed, and fewer new or peripheral problems are likely to be encountered in the commercializing of this burner than with the more complicated recirculation types. Additionally, burner simplicity will ensure lower furnace costs with this choice. The remainder of the paper describes the testing, results, and implementation of that burner.

DISCUSSION

OPTIMUM BURNER/COMBUSTION CHAMBER MATCHING EXPERIMENTS

Experimental Apparatus

The 1 ml/s (gph) optimum low-emission residential oil burner, whose development is detailed in Ref. 5, was used during this study (Fig. 1).

The optimum burner was cyclically fired in a set of three cylindrical research combustors. In conformity with the testing reported in Ref. 2, the burner was fired for 10 minutes of 30-minute cycles. The three combustors constituted a matched set, allowing considerable dimensional, structural, and coolant variations. The basic approach is illustrated in Fig. 2 for one of the chambers. Each chamber was a 1.27 m (5.00 ft) long, flanged section of steel pipe with a stubby, flanged, side-arm section of the same size of pipe attached near one end. The tunnel-fired orientation is illustrated in Fig. 2, in which the oil burner fits into the annular flange depicted at the left end of the chamber. In this orientation, the side-arm was redundant and so was positioned at the opposite end from the burner and simply blanked off. The steel chamber could be either lined with a refractory fiber insert to form an adiabatic combustion zone, or left unlined and cooled by some means. A movable, spiral-wound, finned-tube heat exchanger (shown inserted in the opposite end of the combustion chamber from the burner) provided effective variation of the combustion zone length. To achieve the side-fired configuration, the combustion chamber was simply turned end-for-end, with the blank and burner port flanges relocated as appropriate.

Three chamber diameters were selected such that addition of refractory linings to the larger two would produce lined chambers having inside diameters comparable with the smaller two unlined chambers, viz.:

Steel Pipe ID, m (in.)	Nominal Combustion Chamber ID, m (in.)	Nominal Thickness of Pyroflex, m (in.)
0.162 (6.36)	0.162 (6.36)	--
0.222 (8.75)	0.222 (8.75)	--
0.222 (lined)	0.175 (6.89)	0.024 (0.93)
0.279 (11.0)	0.279 (11.0)	--
0.279 (lined)	0.22 (8.7)	0.030 (1.18)

In use, the major axes of the chamber were vertical, with the burner firing vertically upward when tunnel-fired and horizontally when side-fired.

A water-cooled heat exchanger was used to accomplish rapid cooling of the combustion gases as they flowed out of the primary "firebox" portion of any of the combustion chambers. It was intended that the gas temperature be quenched rather rapidly so that changes in heat exchanger position (i.e., firebox length) could be readily correlated with variations in pollutant emissions. The heat exchanger was a spiral-wound, finned-tube assembly designed to fit inside all three combustors and to be positioned anywhere along the length of a chamber. The exchanger was designed to cool the exhaust gases down to 200 to 350 C (392 to 662 F) at a maximum water coolant flowrate of 3.8×10^{-4} m^3/s (6 gal/min). A 0.0127 m OD by 0.00124 m wall (1/2-in. x 0.049-in.) stainless steel tubing was helically wound with 0.006 m (0.25 in.) high by 0.00051 m (0.020-in.) thick carbon steel fins spaced at 394 fins/m (10 fins/in.). The carbon steel fin material was selected over stainless steel for its higher thermal conductivity and nickel-chrome clad plating provided resistance to corrosive exhaust products. Approximately 4.3 m (14 feet) of finned tubing was required in the construction of the heat exchanger, resulting in a total heat transfer surface area of about 1.4 m^2 (15 ft^2).

Several semicircular baffle plates were cut from 21-gage stainless steel sheet, slipped between coils of the heat exchanger, and wired in place. Cut so their outside diameters would just fit comfortably in the inside diameter of a chamber, the baffles ensured that the gases passed repetitively over the heat exchanger coils and prevented them from bypassing around the outside of the coils.

The optimum burner was fired in the various research combustion chambers at an outdoor test facility whose principal components were attached to a waist-high steel table. A Unistrut superstructure at one end of that table supported the vertically mounted combustion chamber and allowed suspension of the spiral-wound heat exchanger within it. The facility was organized for rapid and easy changing of combustion chambers, burner orientation, and heat exchanger position. Minimum protection from inclement weather was provided by a simple sheet metal roof over the test apparatus.

Experimental data requirements were primarily concerned with flue gas pollutant concentrations. Most pollutant species concentrations were measured by conducting a continuous flue gas sample to a train of analysis instruments located within a nearby laboratory. Flue gas smoke content was measured intermittently at the flue with a manual smoke meter. The instruments used, analyses performed, and types of data obtained are described and discussed in Ref. 5.

Experimental Results

Data were recorded during 160 tests of the apparatus previously described; in addition to chamber diameter, construction, and burner orientation variations, the heat exchanger position and burner excess air level, or stoichiometric ratio, were varied systematically.

Typical measured emission data are illustrated for one subset of these tests in Fig. 3. In this example, flue gas pollutant concentrations varied fairly regularly with both stoichiometric ratio and heat exchanger position, although this was not always consistently so.

The results of all the parametric variations tested were synthesized into a tabular summary form amenable to extraction of trends and design criteria. That summary is given in Table 2, where the first three columns describe the combustion chamber, and the next three columns list the chamber lengths and stoichiometric ratios for which the pollutant concentrations in the flue gas were acceptable. Few of the NO emissions of the combustor were acceptably low so conditions that *minimized* NO production are listed under that pollutant. Further, the right-hand column of Table 2 lists approximate flue gas NO concentrations at 25-percent excess air (12-percent CO_2) for 0.50 m (20 in.) long chambers. It was seen that, with a few exceptions, the combustion chamber designs tested generally failed to achieve the goal of NO < 0.5 g/kg fuel. However, the observed trends in the data support confidence that the goal can indeed be satisfied.

Combustor Design Criteria

Combustor design criteria that can be derived from Table 2 (and the larger body of data upon which it is based), are subdivided into categories of burner orientation, chamber size, and cooling medium in the following paragraphs.

Burner Orientation. Combustion chamber design requirements for ensuring acceptable levels of CO, UHC, and smoke emissions were quite similar for the side- and tunnel-fired burner orientations. That observation held for NO emissions from water-cooled combustors, as well. However, NO production in refractory-lined and air-cooled chambers was about 1 1/2 to 2 times as high in the side-fired orientation as in the tunnel-fired. Ostensibly, this latter phenomenon resulted from substantially longer gas residence times at high temperatures in the stronger and more complicated eddies of a side-fired chamber.

Combustion Chamber Size. Chambers smaller than about 0.20 m (8 in.) ID must be refractory-lined to avoid operating with unacceptable combustion roughness. Operation of all designs was acceptable in this regard when their inside chamber diameter was 0.22 m (8 in.) or larger.

A tendency existed for larger-diameter chambers, with or without insulation, to require longer chamber lengths to achieve comparable levels of carbonaceous pollutants and, concurrently, to produce substantially lower levels of NO. Both phenomena were undoubtedly linked to the ingestion of recirculating combustion gases into the flame zone. For a given burner, larger and stronger recirculation eddies can be established in bigger chambers, reducing the combustion intensity somewhat and lowering the rates of burnout of carbonaceous species. Also, larger-diameter chambers have greater wall areas for convective and radiant transmission of heat from the flame zone, which reduces peak flame temperatures somewhat. Increased average gas residence times should produce opposing trends for both NO production and carbon burnout, which could help account for some anomalies in the data. Also, the steady-state recirculation and radiation effects may be partially masked by starting transient effects, particularly with respect to smoke and UHC data.

Short combustion chambers generally were more favorable for low NO but, if they are too short, the fuel may not be completely burned before combustion reactions are quenched in the heat exchanger. A combustor length of 0.5 m (20 in.) is a suitable compromise for most of the chamber designs tested. Slightly shorter chambers might be appropriate if refractory linings were to be used.

Chamber Cooling Medium. Refractory-lined combustion chambers generally exhibited less combustion roughness and less sensitivity to starting conditions but also produced higher NO concentrations than did cooled-wall combustors. The air-cooled, side-fired configuration had better starting characteristics (but higher NO) than did the air-cooled, tunnel-fired chamber. Water-cooling appeared to be preferable to air-cooling, partially because of lower side-fired NO levels, but also because of smoother starting and more consistent CO and NO emission results. The water-cooled chambers in shorter lengths, however, were prone to produce excessive CO.

It was inferred that the key effect of both air- and water-cooling is the reduction of flame zone temperatures that results from removing heat from the combustor walls. The 0.279 m (11 in.) diameter water-cooled combustor, which met all emission goals, had approximately 20 percent of the heat of combustion of the fuel extracted from the firebox. The single "forced draft" air-cooled chamber was designed to duplicate that heat removal rate, whereas considerably less-effective natural convection prevailed in the other air-cooled configurations. That forced-draft air-cooled chamber, however, had an intermediate 0.25 m (10 in.) ID. Its flue gas NO concentrations were approximately midway between those from the 0.222 m (8 in.) and 0.279 (11 in.) ID water-cooled combustors, indicating that forced draft air-cooling can be just as effective as water-cooling in controlling NO emission levels.

Optimized Combustors for the 1 ml/s (gph) Optimum Burner

To reduce NO emission levels below 0.5 g/kg No. 2 fuel oil burned while maintaining acceptably low carbonaceous pollutant emissions during operation at low excess air levels (10 to 15 percent), the 1 ml/s (gph) optimum oil burner should be fired into a combustor having the following design attributes:

1. Cooled walls, with either water or forced-draft air coolant, which extract approximately 20 percent of the heat of combustion of the fuel from the flame zone. It is also important to design for nearly uniform inside wall temperatures and for retention of elevated wall temperatures during standby periods.
2. The ID of the combustor should be 0.28 m (11 in.) or greater. (It is inferred that NO emission levels will continue to go down as diameter is increased above 0.28 m (11 in.), but this hypothesis has not been tested.)

3. The effective combustion chamber length, from the burner end to the location where the furnace heat exchanger begins to quench the combustion gas temperature rapidly, should be greater than 0.5 m (20 in.) and perhaps as long as 0.75 m (30 in.).
4. The combustor may be either side-fired or tunnel-fired, whichever is convenient for a particular furnace or boiler design.

CONCEPTUAL PROTOTYPE FURNACE DESIGNS

Preliminary conceptual designs were laid out for a prototype warm-air furnace and a prototype hydronic boiler, each embodying the preferred approaches previously discussed for improving efficiency and reducing emissions. Each design concept layout was discussed with one or more representatives of a manufacturing company that makes and markets residential space heating equipment. Thereafter, the designs, the manufacturer's comments, criticisms and suggestions, and appropriate design modifications were reviewed with the EPA Project Officer preparatory to selecting one of the designs for fabrication and experimental evaluation.

The preliminary conceptual designs are illustrated and briefly described. Greater detail is given in Ref. 7.

Conceptual Design: Warm-Air Furnace

A conceptual design layout for a prototype low-emission, improved-efficiency, warm-air furnace is shown in Fig. 4. It is based upon modifying an existing, commercially purchased, warm-air furnace* to accommodate an optimized, low-emission oil burner with sealed air supply and a large, air-cooled, steel combustion chamber. This approach allows key concepts to be tested without the expense and delay of designing and fabricating most furnace components. Further, it ensures that commercially practical heat exchangers, air filters, blowers, cabinets, and controls are imposed upon the concepts to be evaluated.

Referring to Fig. 4, the burner vestibule is a closed volume supplied with combustion air, through a small filter, from an external, sealed air system. Not shown is a positive shutoff device for this air when the burner is inactive; this device might be a solenoid-actuated butterfly valve in the combustion air inlet line.

---

*A Lennox Model 011-140 furnace was selected.

The combustion chamber is offset slightly toward the back of the furnace to accommodate its large diameter. The chamber is comprised of a standard pipe cap welded to an eccentric reducer whose small end is mated to the furnace heat exchanger. Welded to its outside are many longitudinal fins to enhance transfer of heat to the vertically upflowing, coolant air. The fins also act as a heat sink to help keep the combustion space warm during standby periods.

Conceptual Design: Hydronic Boiler

The conceptual design layout for a prototype, low-emission, improved-efficiency hydronic boiler is shown in Fig. 5. This design is based on substantially all-new construction, principally because no commercially available unit was identified as being readily adaptable to the larger-diameter, water-cooled combustion chamber for the optimum burner.

A horizontal, tunnel-fired, water-cooled combustion chamber was selected because it offers boiler structural and package volume advantages. The horizontal firebox is followed by multiple sequential passes through a water-cooled, fire-tube heat exchanger. Commercially available Turboflue internally finned tubing is indicated for this service. The combustion chamber and heat exchanger tubes are all attached to the same boiler tube sheets. Between the combustion chamber and the first heat exchanger pass, combustion gases are reversed by passage through an insulated 180-degree return manifold, whose volume is considered to be part of the combustion chamber. Similarly, there are 180-degree return manifolds between successive heat exchanger passes.

The conceptual hydronic boiler design also has the usual plumbing and control features needed for installation and operation in a residence, including a tankless coil for heating domestic hot water. Needed, but not shown in Fig. 5, is an exterior cabinet that should be well insulated to reduce external heat losses.

FUTURE WORK PLANS

Following comparative assessments of the two preliminary prototype designs, including their potential overall emissions and fuel economy impact, the warm-air system was selected as the more promising; therefore, a prototype warm-air unit will be built for further study in the continuing work. The data and experiences gained will be applied to the final design of a cost-competitive, commercially producible, warm-air furnace that embodies the derived low-emission, improved-efficiency technology.

REFERENCES

1. Hall, R. E., J. H. Wasser, and E. E. Berkau, "NAPCA Combustion Research Programs to Control Pollutant Emissions From Domestic and Commercial Heating Systems," New and Improved Oil Burner Equipment Workshop, NOFI Tech. Publ. 108 ED, National Oil Fuel Institute, Inc., New York, New York, September 1970, pp. 83-93.

2. Hall, R. E., J. H. Wasser, and E. E. Berkau, "A Study of Air Pollutant Emissions From Residential Heating Systems," EPA-650/2-74-003, Environmental Protection Agency, Research Triangle Park, N.C., January 1974.

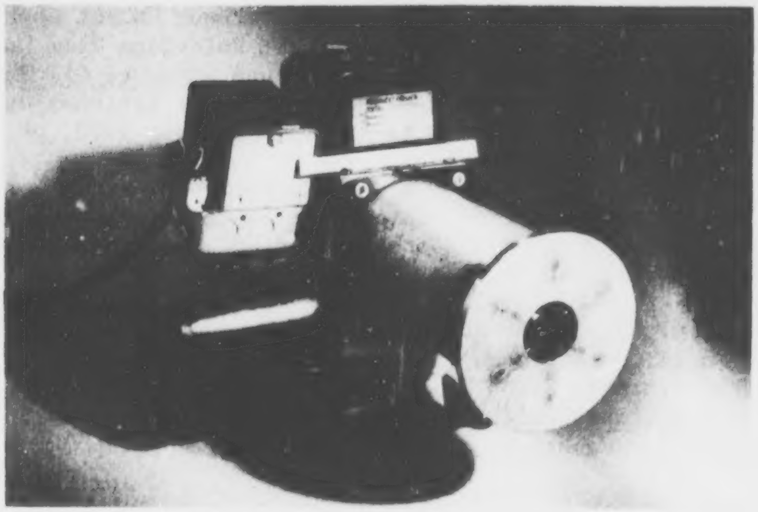
3. Martin, G. B., and E. E. Berkau, "Evaluation of Various Combustion Modification Techniques for Control of Thermal and Fuel-Related Nitrogen Oxide Emissions," presented at the Fourteenth Symposium (International) on Combustion, Pennsylvania State University, August 1972.

4. Barrett, R. E., S. E. Miller, and D. W. Locklin, "Field Investigation of Emissions from Combustion Equipment for Space Heating," EPA R2-73-084a (API Publ. 4180), Environmental Protection Agency, Research Triangle Park, N.C., June 1973.

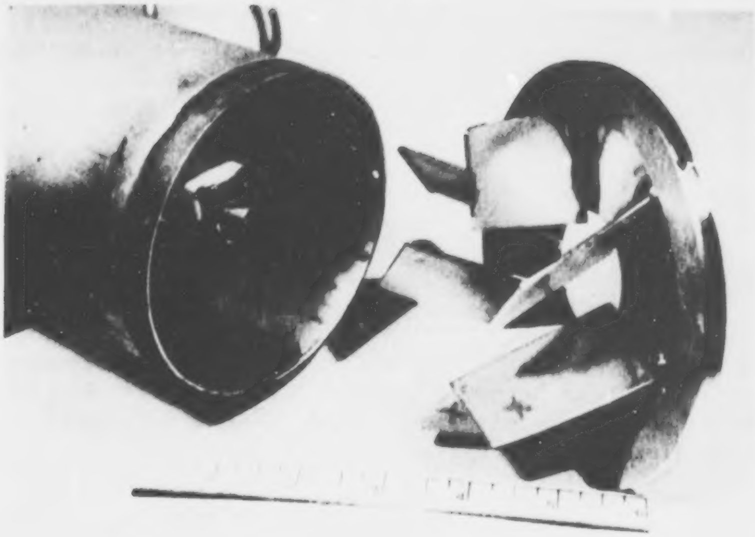
5. Dickerson, R. A., and A. S. Okuda, "Design of an Optimum Distillate Oil Burner for Control of Pollutant Emissions," EPA-650/2-74-047, Environmental Protection Agency, Research Triangle Park, N.C., June 1974.

6. Peoples, G., "Sealed Oil Furnace Combustion System Reduces Fuel Consumption," Addendum to the Proceedings, Conference on Improving Efficiency in HVAC Equipment and Components for Residential and Small Commercial Buildings, Purdue University, Lafayette, Ind., October 1974.

7. Combs, L. P., and A. S. Okuda, "Residential Oil Furnace Optimization," Interim Report for Phase I of Contract 68-02-1819, R-9815, Rocketdyne Division, Rockwell International, Canoga Park, California, draft submitted to EPA, August 1975.



EXTERNAL VIEW



OPTIMUM HEAD

Figure 1. 1 ml/s (gph) Optimum Low-Emission Residential Oil Burner

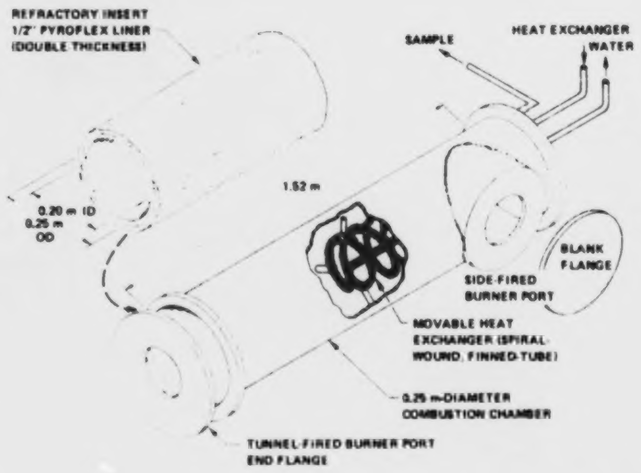

REFRACTORY INSERT
1/2" PYROFLEX LINER
(DOUBLE THICKNESS)
SAMPLE
HEAT EXCHANGER
WATER
1.52 m
0.20 m ID
0.25 m
OD
BLANK
FLANGE
SIDE-FIRED
BURNER PORT
MOVABLE HEAT
EXCHANGER (SPIRAL-
WOUND, FINNED-TUBE)
0.25 m-DIAMETER
COMBUSTION CHAMBER
TUNNEL-FIRED BURNER PORT
END FLANGE

Figure 2. Experimental Combustion Chamber Arrangement

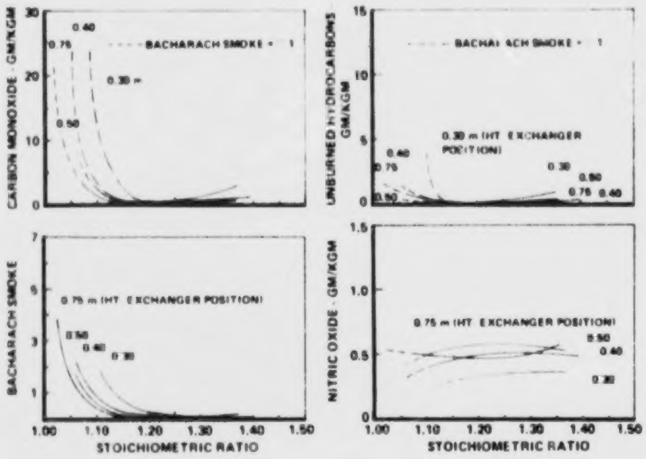


Figure 3. Cycle-Averaged Flue Gas Emissions, 10 ml/s Optimum Oil Burner in a 0.279 m Diameter, Air-Cooled, Side-Fired Combustor at Various Heat Exchanger Positions

Reproduced from
best available copy.

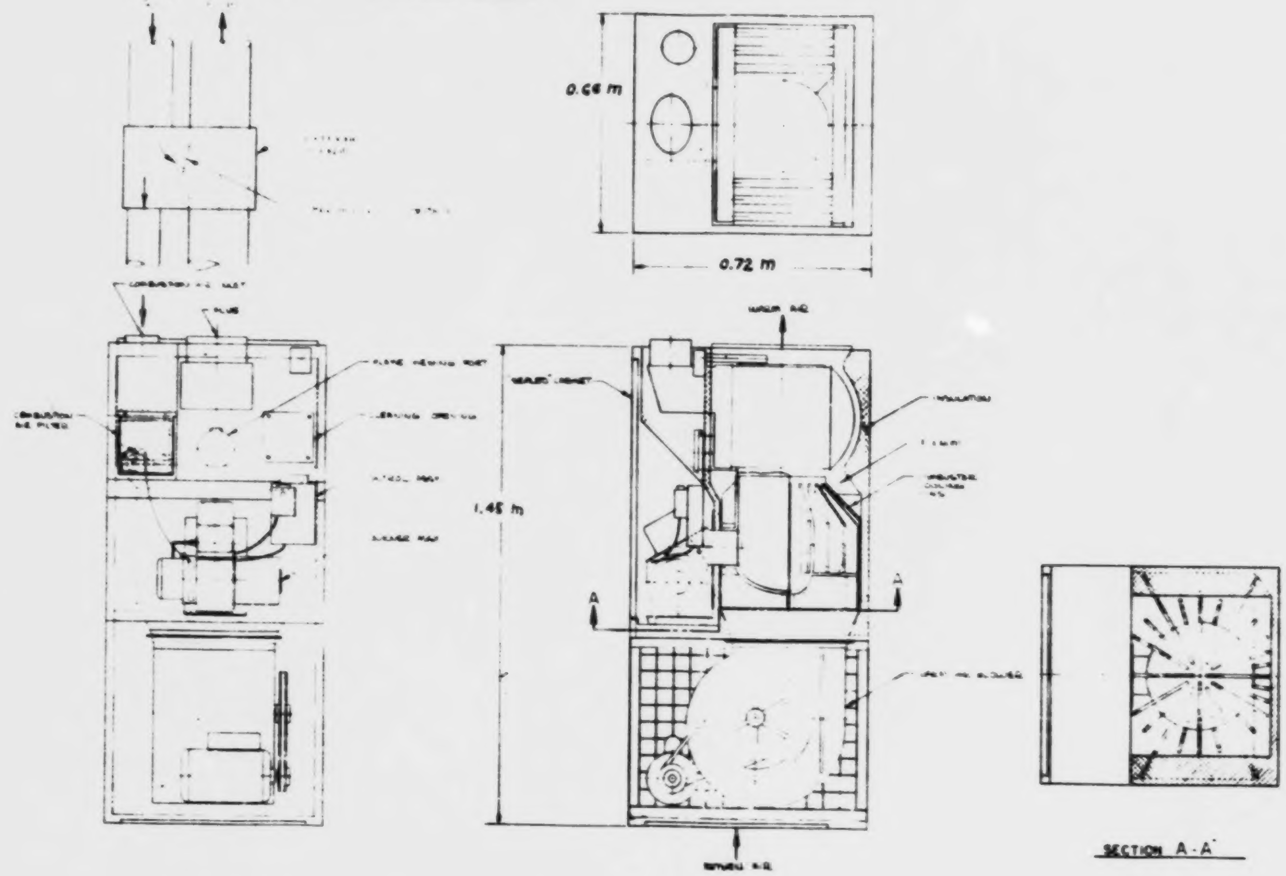

0.64 m
0.72 m
1.45 m
COMBUSTION AIR INLET
FLUE
FLAME VIEWING PORT
CLEANING OPENING
COMBUSTION AIR FILTER
WARM AIR
INSULATION
A
A
RETURN AIR
SECTION A-A'

Figure 4. Conceptual Prototype: Low-Emission, Warm-Air Furnace

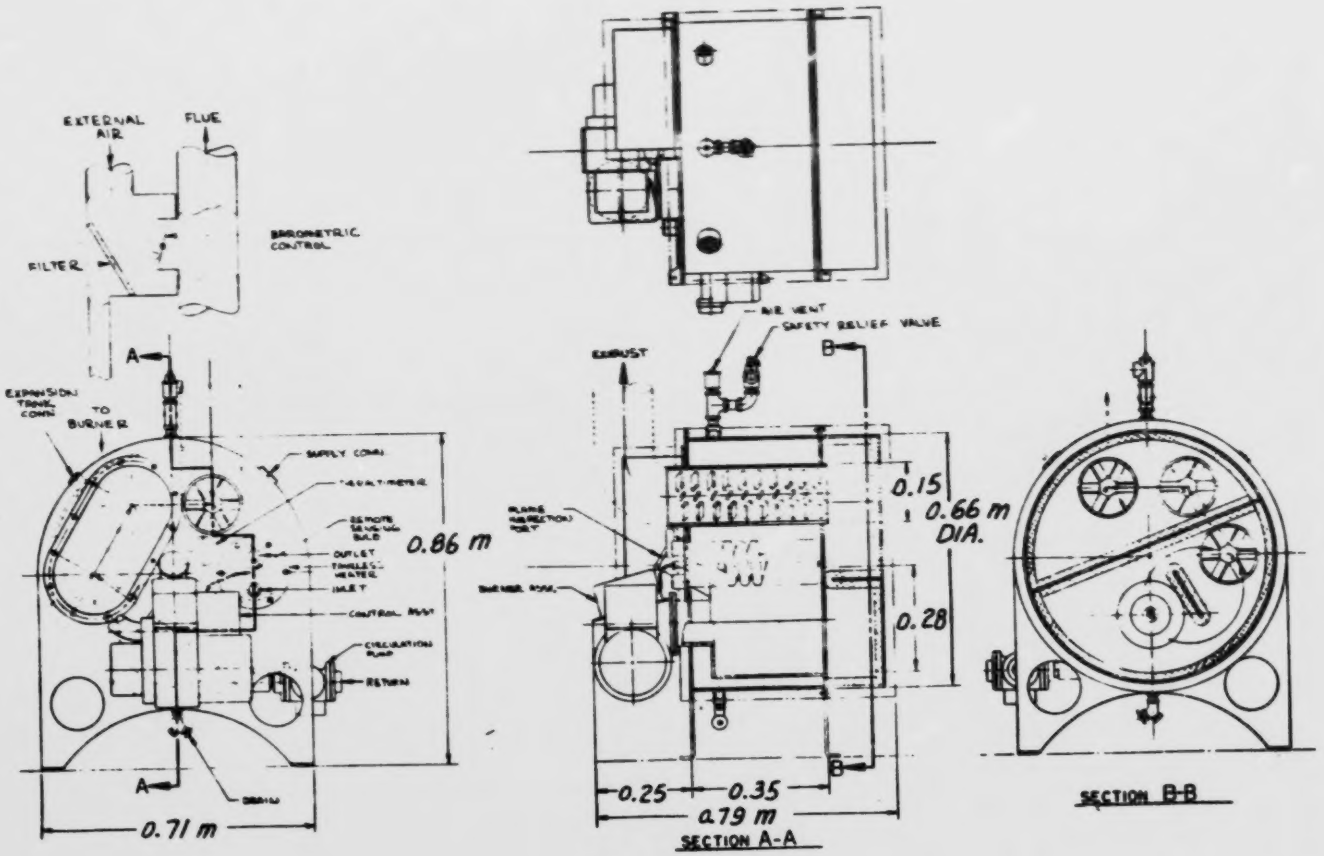

EXTERNAL AIR
FLUE
BAROMETRIC CONTROL
FILTER
A
EXPANSION TANK CONN
TO BURNER
SUPPLY CONN
REMOTE SENSING BULB
OUTLET
TANKLESS HEATER
INLET
CONTROL ASSY
CIRCULATION PUMP
RETURN
DRAIN
A
0.86 m
0.71 m
AIR VENT
SAFETY RELIEF VALVE
EXHAUST
B
FLAME INSPECTION PORT
BURNER ASSY.
0.15
0.66 m DIA.
0.28
B
0.25
0.35
0.79 m
SECTION A-A
SECTION B-B

Figure 5. Conceptual Prototype: Low-Emission Hydronic Boiler

TABLE 1. TYPICAL EMISSION AND EFFICIENCY PERFORMANCE OF RESIDENTIAL OIL FURNACES

	AVERAGE OF EXISTING FURNACE POPULATION	AVERAGE OF CURRENT NEW UNITS
CYCLE AVERAGED EMISSIONS		
SMOKE (BACHARACH SCALE)	~ NO. 2	~ NO. 1
CO	~ 0.6 G/KG FUEL	~ 0.3 G/KG FUEL
UHC	~ 0.08 G/KG FUEL	~ 0.06 G/KG FUEL
PARTICULATES	~ 0.3 G/KG FUEL	~ 0.2 G/KG FUEL
NO_x	~ 2.5 G/KG FUEL	~ 2.5 G/KG FUEL
THERMAL EFFICIENCIES (NET)		
STEADY-STATE	65 TO 75%	75 TO 80%
CYCLE AVERAGED	50 TO 60%	65 TO 70%

TABLE 2. SUMMARY OF RESULTS FROM 1 ML/S (GPH) OPTIMUM BURNER/COMBUSTION CHAMBER MATCHING EXPERIMENTS

CHAMBER DESIGN ATTRIBUTES			REQUIREMENTS FOR ACCEPTABLE (OR MINIMUM) EMISSIONS			NO, g/kg FUEL @ L = 0.5 m & 1.25 S R
CONFIGURATION	COOLING METHOD	I D, m	CO & UHC	SMOKE (≤ NO. 1)	NO	
TUNNEL-FIRED (COAXIAL)	AIR-COOLED	0.162	ROUGH-BURNING THROUGHOUT OPERATING RANGE			
	(STARTABLE OVER A VERY NARROW SR RANGE)	0.222	$L_c \geq 0.5$ m	SR ≥ 1.25	$L_c \approx 0.4$ m	(0.6)
		0.279	$L_c \approx 0.75$ m	SR ≥ 1.1 OR $L_c > 0.5$ m	$L_c \approx 0.4$-5.0 m	(0.4)
	WATER-COOLED	0.222	$L_c > 0.5$ m	SR > 1.15	SHORT L_c'S BEST	0.7
	INSULATED	0.175	$L_c \geq 0.5$ m	$L_c \geq 0.75$ m OR SR > 1.3	SHORT L_c'S BEST	1.3
		0.22	$L_c \geq 0.5$ m	$L_c \geq 0.5$ m & SR > 1.15	SHORT L_c'S BEST	0.9
SIDE-FIRED (PERPENDICULAR PORT)	AIR-COOLED	0.162	ROUGH-BURNING THROUGHOUT OPERATING RANGE			
		0.222	$L_c \geq 0.5$ m	$L_c \geq 0.5$ m SR ≥ 1.15	$L_c < 0.75$ m SLIGHT FAVOR	0.9
		0.279	$L_c \geq 0.4$ m & SR ≥ 1.15	$L_c \geq 0.5$ m & SR ≥ 1.08	SHORT L_c'S BEST	0.6
	(FORCED DRAFT)	0.250	$L_c \geq 0.5$ m	$L_c \geq 0.5$ m, SR > 1.06	SHORT L_c'S BEST	0.8
	WATER COOLED	0.222	$L_c \geq 0.5$ m	$L_c \geq 0.5$ m & SR > 1.2	SHORT L_c'S BEST	0.7
		0.279	$L_c \geq 0.5$ m	$L_c \geq 0.5$ & SR ≥ 1.1	SHORT L_c'S BEST	0.4
	INSULATED	0.175	$L_c \geq 0.3$ m	$L_c \geq 0.5$ m & SR ≥ 1.25	SHORT L_c'S BEST	2.0
		0.22	$L_c \geq 0.5$ m	$L_c > 0.5$ m & SR ≥ 1.15	DATA MIXED	1.9

10:05 a.m.
Integrated Low Emission
L. Paul Combs, Rocketdyne

Q: Am I right that you still need about 20-25% excess air for a normal operation to obtain zero smoke number?

A: That chart was not typical of our current testing. With the optimized firebox, we have designed the prototype furnace to operate at 15% excess air.

Q: Have you experienced blue flame phenomenon in the course of your work?

A: With the recirculating gas burners, yes, we did have blue flame condition.

Q: Did you think it worthwhile to consider that as an extension of your research?

A: It has promise for further reducing the NO to levels perhaps half of our target here, on the order of a quarter of a gram per kilogram. However, it has difficulties. The blue flame burners are hard to start because the combustion chamber is filled with colder gases than during steady state.

Q: Do you have to design a combustion chamber for your particular burner or vice versa? Does there have to be a mating of burner design and combustion chamber design or can this be a conversion burner?

A: The optimization work that we have done has all been done with one gallon per hour firing levels. We have done a small amount of experimentation at different firing rates and the indication is that the combustion chamber can take some latitude in firing rate. I think it is best optimized for a particular firing rate. We are working on another contract in which we are assessing the direct commercial application of the optimum burner head for use as a retrofit device for existing furnaces.

Q: In the beginning of your talk, you mentioned that one of your goals was to make something that would fit codes, and I question the shutoff damper in the exhaust flue line. I rather suspect that that has got to be a code problem. Did you look into that?

A: We discussed it with the enginnering people at Lennox. The shutoff device that we had originally sketched in our design they objected to pretty strenuously, from that standpoint. The use of a solenoid actuated butterfly valve they thought would have no problem in passing code. It may introduce other problems that impact the codes. The draft air flow through the burner and firebox helps to keep components such as the electrodes, the flame sensing cadmium sulfide cell, the electrical wiring, the control wiring and the vestibule cooled. With that air shut off, we may have difficulty with too high temperatures and need to put in additional insulation and so on.

Q: Your design burner is going to operate at 15% excess air. Now does that represent the excess air level as measured in the flue also? Most heat exchangers like Lennox (I have a Lennox in my house) are not designed to take the flame temperatures that result with 15% excess air. And that is why on a normal household burner, there is a large amount of excess air used just because heat exchangers are typically not made out of a high alloy material, and you are talking about gas to gas heat exchangers. Now, you say 15% excess air gives a high thermal efficiency if you maintain it through the whole thermodynamic boundary of your system. Do you do that?

A: It is our intention to do that. We are helped in that regard by the fact that we are going to remove 20-25% of the heat from the combustion chamber so that the combustion gases will be at least partially cooled by the time they hit the heat exchanger.

Q: When you say you hope to, this means that you haven't been able to do it in your prototype furnace?

A: We haven't built a prototype furnace. We have designed it and it is being built now.

[Moderator]

Since we shut off the questions on Paul's presentation, he has agreed to endure double jeopardy; and if Rix Beals and the other gentlemen are still here and would like to ask their questions, we would welcome them at this time.

Q: Paul, what was the final temperature, not after dilution but after leaving the heat exchanger on the integrated furnace setup? I understood it was operating at 15% excess air but I couldn't see the chart from the back and I wasn't sure what the final temperature was.

A: The chart didn't tell what the final temperature is. We anticipate that we will probably have flue gas temperatures on the order of 400° F. We have run some computer analyses of the behavior of the existing Lennox compact heat exchanger that we will use downstream with the combuster but our analyses are a little uncertain as to what is going to happen. That's part of the testing that will be performed, to characterize the behavior of the firebox within the combustion chamber and the heat exchanger combination.

Q: The second point that I wanted to ask is not intended controversially or that sort of thing; but I quite often see and hear comments regarding the advantages of using an outside air source and I won't attempt to dispute that there are energy savings. However, have you in your consideration or percentage assignments or evaluations of this taken into account the fact that the load on the heat exchange or combustor system is increased when it is looking at colder combustion air than when it is looking at inside combustion air (let's say the 70 degree differential that might exist which in turn might distort the apparent advantages of using outside air)? I might re-express that: you are raising the same mass or volume of combustion air, but you are raising it, say, in case (1) if it were outside design at zero you might be raising it from zero to 400 or 500 final exit. Whereas in case (2) using inside air one might be raising it from 70 to 400 or 500 outside. Has that been allowed for in your evaluation?

A: We ran a substantial number of computer analyses simulating the furnace system that I didn't talk about before. The analytical portion did include examination of the effect of varying the combustion air temperature and it does have a very modest impact on the furnace thermal efficiency. I might say that there is a several hundred page interim report that has been submitted to EPA in draft form, and if things go according to plan that will be available toward the beginning of next year, for those who want more detail on that material. I didn't point out at the beginning of my presentation that I do have co-authors. One sent me a note saying I should have mentioned that we did run a preliminary test on the finned firebox and found that as opposed to the cylindrical combustion chamber I illustrated, it was capable of removing the heat required and that the emissions were surpressed as predicted.

Q: I would like to offer one comment to clarify the question Rix just asked you. The comment regards the relationship between the air that the furnace requires and the contribution of that air to the building infiltration. Now in your analysis, if I heard it correctly, you assume that all the air that the furnace needs for combustion and for draft control comes sooner or later from outside. Rix wondered what happens if you compare that with the other situation where you have to increase the heating for the same mass of air through a larger differential. Now, to add to the confusion, we did some measurements last heating season, and it turns out that not all the air that the furnace needs for combustion and for draft control comes directly from outside, or, in other words, contributes infiltration. Typically between 30% and 100% of that air contributes infiltration. Meaning that some of the air that goes to the furnace is really coming from a reduction in the exfiltrating air through the cracks near the attic where you have a higher inside pressure compared to the outdoor pressure. In some houses, depending on how they are built, whether one or two stories, and depending on how leaky they are, all the air that is required by the furnace comes from increased infiltration. If I didn't know anything about a house, I would guess that about 70% of the furnace air requirements contribute to infiltration. A year ago when I didn't know anything about that, I assumed like you did, that 100% is a contribution. The question regards the effect of combustion chamber size on smoke and NO increase or decrease, and I think your conclusion was as you increase combustion chamber size your NO generally goes down. Is the same true for smoke or was the smoke going the other way?

A: It is true, there is a tendency that as the combustion chamber diameter is increased to surpress the NO formation, a somewhat longer chamber is required to burn out the products of incomplete combustion. CO and the unburned hydrocarbons did go up and so we would use a longer combustion chamber to keep them down.

Q: I see; so really you have to maintain the volume, so to speak, to maintain the soot burnout the same; but by reducing the diameter you can reduce the NO. Is that correct?

A: Yes, that is correct. Concerning your comment, I might say that we have not tried analyzing the residence itself. Our analysis has been restricted to the furnace unit and the inputs and outputs that it experiences.

Q: When you take the combustion air from outside the building, and, of course, assuming that you possibly could have an installation of this type in quite cold climates, would not the inlet air temperature have some effect on your combustion process, and possibly your emission levels? Also, since the device has a centrifugal fan, the actual air temperature and the consequent density is going to determine somewhat the fan output pressure, which will somewhat affect the combustion air flow throughout the system. Would you have any comment on that?

A: You are right, there will be effects. The thermal effect is really pretty marginal. I don't recall, nor do I have here, the graphs of the decrease in thermal efficiency as a result of the colder air supply. I don't know about the emissions; it is conceivable that there might be a slightly higher starting spike on the CO and unburned hydrocarbons. The colder air temperatures, as the airflow is established before ignition is established, will tend to chill the combustion chamber more, and it could conceivably have a starting spike effect. Yes, I'm sure it will.

THE CONTROL OF POLLUTANT EMISSIONS
FROM
OIL FIRED PACKAGE BOILERS

By:
M. P. Heap, T. J. Tyson, E. Cichanowicz
Ultrasystems, Inc.,
and
R. E. McMillan, F. D. Zoldak
The Foster Wheeler Energy Corporation

Preceding page blank

ACKNOWLEDGEMENTS

The authors wish to acknowledge the help and guidance given by Mr. G. B. Martin, EPA Project Monitor for the current projects and all the members of the EPA-API Steering Committee. We are grateful to Mr. W. Axtman of the ABMA for his assistance on various matters concerning package boiler practice and boiler sales data. Mr. McComis was responsible for all the laboratory investigations and the authors gratefully acknowledge the help of Mr. R. E. Sommerlad of the Foster Wheeler Energy Corporation. Dr. L. J. Muzio was responsible for Phase I and II of the EPA-API program.

1.0 INTRODUCTION

A package boiler is described in the ABMA Lexicon as:

> "a boiler equipped and shipped complete with fuel burning equipment, mechanical draft equipment, automatic controls and accessories. Usually shipped in one or more major sections."

Although boilers with a capacity up to 250,000 lbs of steam per hour can be shipped as a single unit by rail or truck, larger units (250,000 to 350,000 lbs of steam per hour) must be modularized. Thus the term packaged encompasses a wide range of equipment, size range, design type and fuel capability. This paper is somewhat more limited in scope since it is mainly concerned with firetube boilers and practical experiments with equipment in the lower size range (up to 25,000 lbs of steam per hour). However, it is contended that the general principles established from these experiments with regard to pollutant formation are applicable to the complete range of package boilers firing oil.

The genesis for the results presented in this paper was a recently concluded program jointly supported by the EPA and API. The objective of this program was to provide information on the control of nitrogen oxide emissions from package boilers by the use of flue gas recirculation or staged combustion techniques, and this work is currently being continued under EPA support (EPA Contracts 68-02-1498 and 68-02-1500). Several workers have established the influence of the fuel/air/combustion product mixing processes on NO_x formation in turbulent diffusion flames [1,2 and 3]. Results of this investigation emphasize that due regard must also be paid to those design features which control these mixing processes in order to maximize the effectiveness of both staged combustion and flue gas recirculation as NO_x control techniques. Thus, in the ongoing projects emphasis is placed upon optimizing the total combustion system to achieve NO_x control.

The EPA-API program consisted of three separate phases:

Phase I - Construction of a versatile combustor

Phase II - Experimental investigations in that versatile combustor to determine the optimum method of applying both flue gas recirculation and staged combustion to control NO_x emissions

Phase III - Demonstration of the applications of these techniques to operating boilers in the field

The results of the initial phases of this program have been reported elsewhere [4,5] and the third phase has recently been completed [6]. A decision to proceed with the field tests was made even though the results of the experimental investigations were not encouraging. The results of the laboratory investigation aimed at optimizing control techniques have been summarized by Muzio, Wilson and McComis [5].

- a 20 percent reduction in NO_x emission could be achieved either by reducing the amount of primary air or by increasing the atomizing air pressure;

- maximum reductions of 25 percent could be achieved by deliberately staging the heat release before smoke emissions became excessive;
- a 30 percent reduction in emission level could be obtained by adding cooled flue gases to either the total or the primary air streams;
- it was possible to achieve a 45 percent reduction in NO_x emissions by combined application of staged combustion and flue gas recirculation.

This paper briefly describes the results of the field test and recent laboratory investigations which have been conducted both to explain earlier results and to provide information on the optimum design of combustion systems for package boilers. The optimum design must satisfy the dual criteria of minimum pollutant emissions and maximum efficiency where efficiency relates to both thermal and operating efficiency.

2.0 EMISSION CONTROL FROM PACKAGE BOILERS - FIELD TESTS

The influence of flue gas recirculation on NO_x emissions has been determined in two package boilers of different design types (watertube and firetube). The influence of delayed air addition, in order to stage combustion, has also been established in the same firetube boiler. This work was supported in part by the original EPA-API program and the field tests were carried out by the Foster Wheeler Energy Corporation.

2.1 Design of the Equipment

The boilers tested during the field demonstration were both located in the same boiler house and represent a compromise between that which was considered ideal and that which was practically attainable. In selecting the field units the following criteria were considered to be of particular importance:

- the units to be tested should be typical of modern practice. The value of the investigations would be negated if the data were to be obtained on equipment of outmoded design
- the units tested should reflect the bulk of the population of industrial boilers both with respect to type and size
- the units should be capable of burning both natural gas and residual oil
- the same oil supply should be burned in both units
- it should be possible to apply both flue gas recirculation and staged combustion to the units
- the owners of the units must be cooperative since the tests could not be carried out without some interruption of the normal routine

The aid of the American Boiler Manufacturers Association was solicited in order to determine the type, size and characteristics of the "typical" package boiler. The ABMA were most helpful and provided data on the total sales of boilers for a ten year period. This data indicated that the bulk of the population was in the range 3,450 to 6,900 lbs of steam per hour for the firetube design and 21,000 to 50,000 lbs of steam per hour for the watertube design.

A decision was made to investigate the influence of boiler design on pollutant emissions rather than the effect of boiler size for the same design. Both the units chosen for testing were located in the same boiler house and therefore one important criteria, that of common fuels, was satisfied. A complete description of the boilers and the modifications made to allow the application of flue gas recirculation has been given elsewhere [6]. The forced draft firetube boiler burned both natural gas and No. 5 fuel oil and was rated at 12 x 10^3 lbs per hour of steam at 15 psig. The watertube boiler was also designed to fire the same fuels, however, a steam rather than an air atomized oil nozzle was used in this unit. Although both boilers were built by the same manufacturer, they were fired by different burner designs.

The flue gas recirculation systems designed and installed in each boiler were capable of recirculating approximately 30 percent of the combustion products at full load. The recirculation was drawn from the stack through a metering orifice of standard ASME design and the recirculation was controlled by a damper at the discharge of the recirculation fan. The wind box of both boilers was breached to provide an entry for the cooled recirculation. Front views of both boilers are presented in Figures 1 and 2 which show the location of the flue gas recirculation systems.

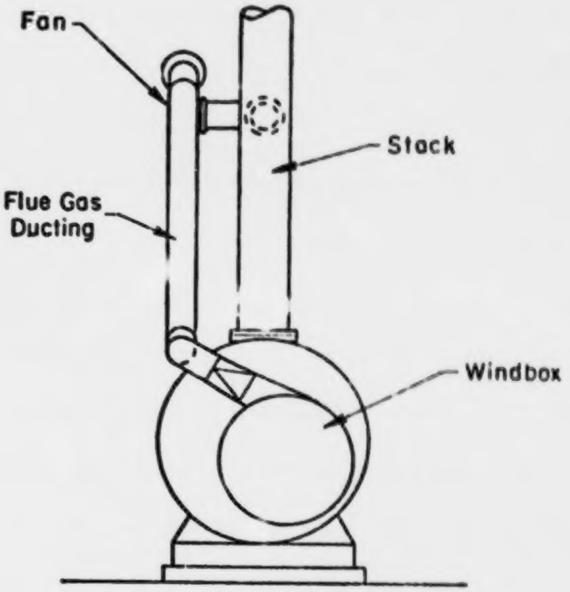

Fan
Stack
Flue Gas Ducting
Windbox

Figure 1. Front View of Firetube Boiler Showing the Location of the Flue Gas Recirculation System

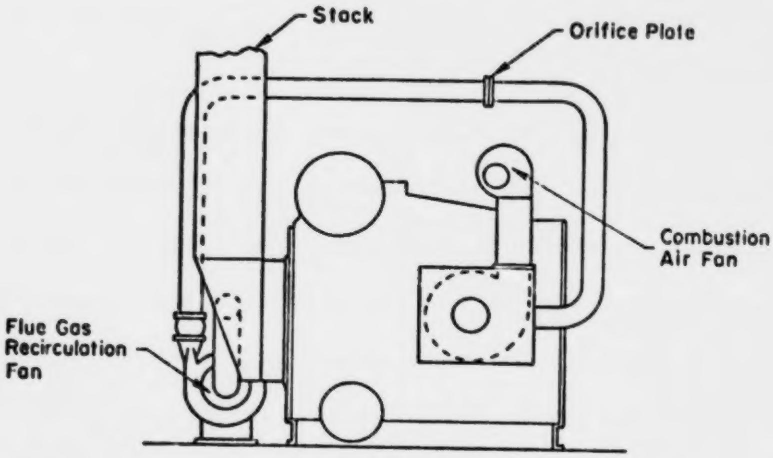

Stack
Orifice Plate
Combustion Air Fan
Flue Gas Recirculation Fan

Figure 2. Front View of Watertube Boiler Showing the Location of the Flue Gas Recirculation System

Staged combustion investigations were only carried out in the firetube boiler. Figure 3 shows the general arrangement of the staged combustion system. Air supplied by a separate fan was injected radially into the firetube through eight fishtail injectors. The axial location of the injectors (X see Figure 3) could be varied to determine the optimum position for staged air injection. The staging system was uncooled, and therefore, the staging air was heated prior to injection. However, the temperature of the second stage air upon injection was not measured.

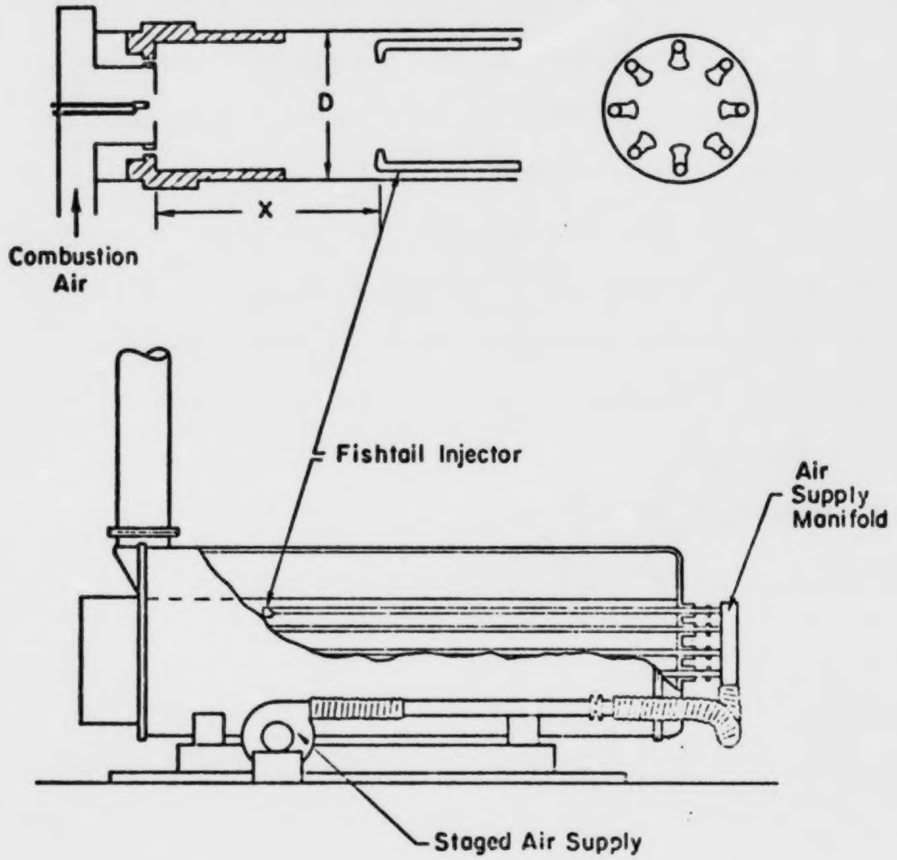

D
X
Combustion Air
Fishtail Injector
Air Supply Manifold
Staged Air Supply

Figure 3. Details of Staged Combustion Equipment in the Firetube Boiler

Flue gas samples were withdrawn from the stack through a stainless steel probe and cooled in an ice bath. The composition of the flue gases were monitored continuously and the NO_x results reported below were obtained by an analyzer based upon the chemiluminscent principle.

2.2 Results

Flue Gas Recirculation

Figure 4 shows the influence of flue gas recirculation on NO_x emissions from both boilers at fixed excess air and three loads. Reductions of the order of 30 percent were possible in the firetube boiler and the limit was imposed by the capacity of the recirculation system. Only modest reductions could be attained by recycling cooled combustion products through the windbox of the watertube boiler. However, in this case the limit was imposed by flame stability and not the capacity of the recirculation system. Figure 4 also shows that for all watertube boiler loads recirculation of combustion products initially caused an increased emission. The addition of flue gases did not significantly affect either smoke or carbon monoxide emissions in either boiler.

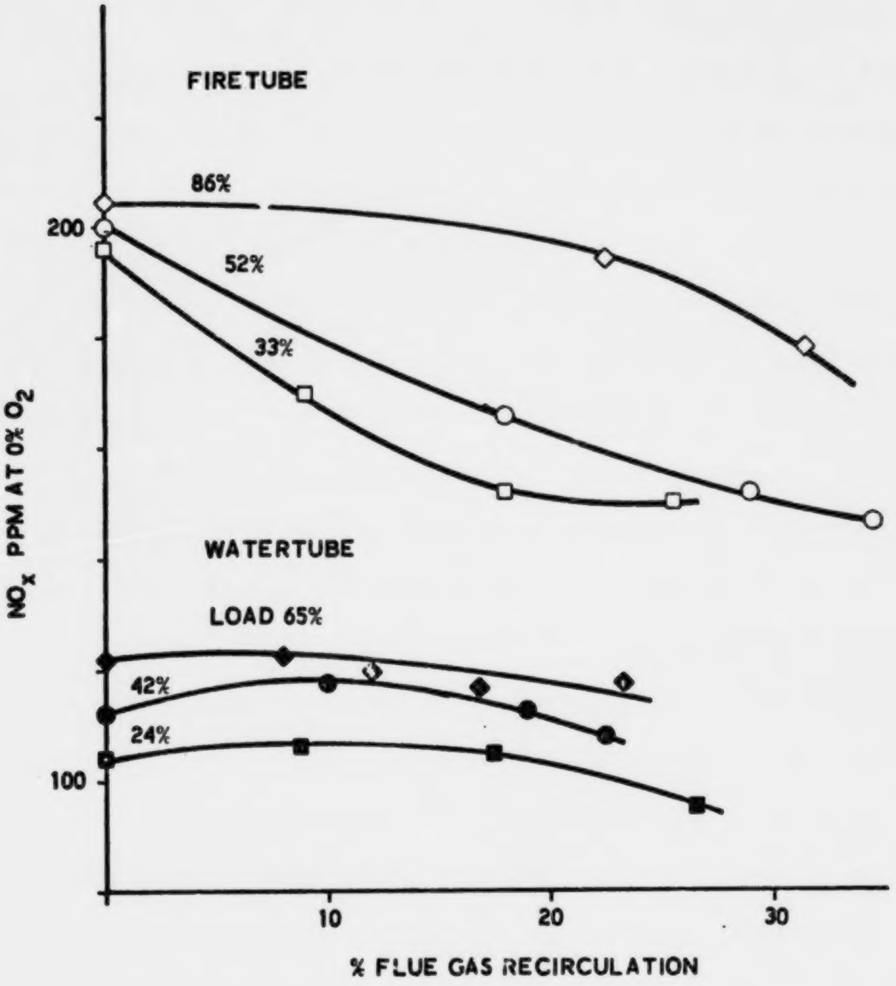


Figure 4. The Influence of Flue Gas Recirculation and Load on NO$_x$ Emissions from a Watertube and a Firetube Boiler at 20 Percent Excess Air

Staged Combustion

The insensitivity of NO_x emissions to the overall excess air during staging is shown in Figure 5. However, as expected, NO_x emissions are strongly dependent upon burner stoichiometry (i.e., the fraction of combustion air passing through the windbox). The influence of the location of the staged air injectors on NO_x emissions can also be seen in Figure 5. The fractional reduction increases as the injection point moves downstream. In the system tested, there appears to be an optimum burner stoichiometry for minimum NO_x emissions. However, this minimum optimum level is probably peculiar to this system and is probably associated due to the presence of unreacted fuel nitrogen compounds at the point of staged air injection. In the laboratory experiments increased smoke emissions were observed as a direct tradeoff for decreased NO_x emissions, whereas in the field tests excessive smoke emissions were only observed at low excess air levels and carbon monoxide emissions give a better indication of deteriorating combustion conditions within the firetube. Figure 6 compares the influence of the location of the staging injectors on both NO_x and CO emissions for a fixed burner stoichiometry. It can be seen that the initial NO reductions were not accompanied by a large increase in the CO emission. However, with the injectors located at the furthest distance from the burner the CO emission increases significantly, suggesting that the

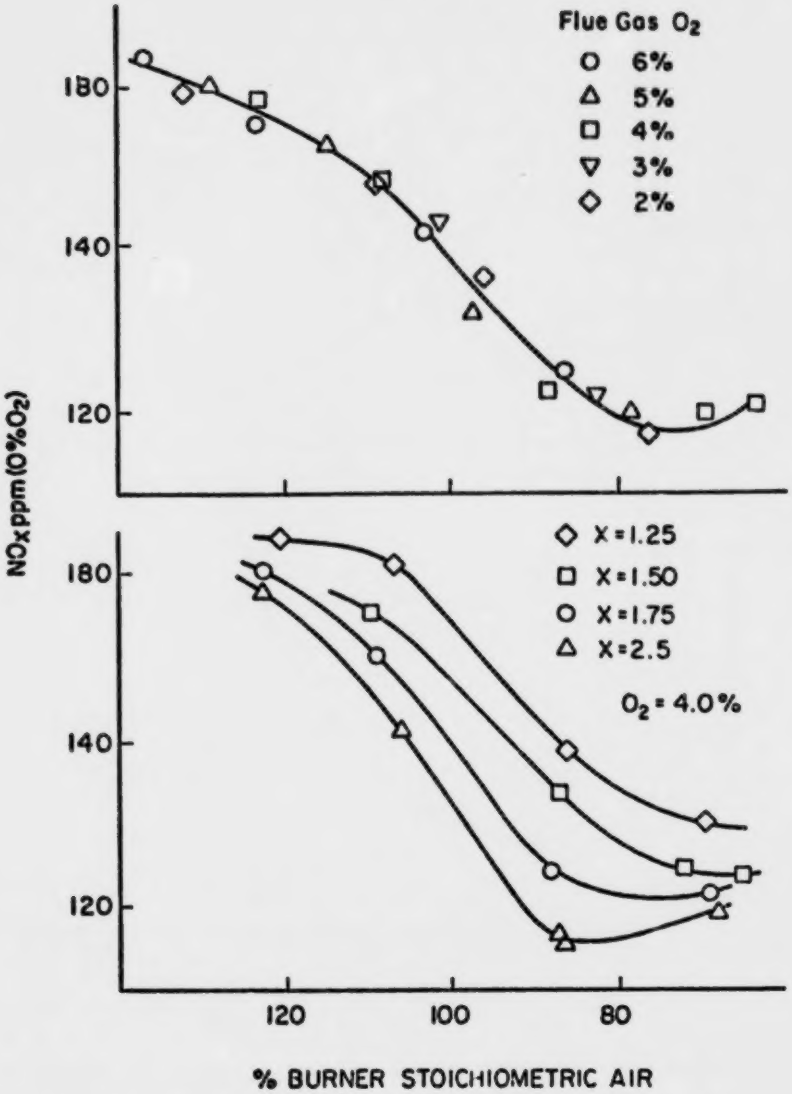


Figure 5. The Influence of Overall Excess Air and Location of Staged Air Injection During Staged Combustion Tests on the Firetube Boiler (60 Percent Load)

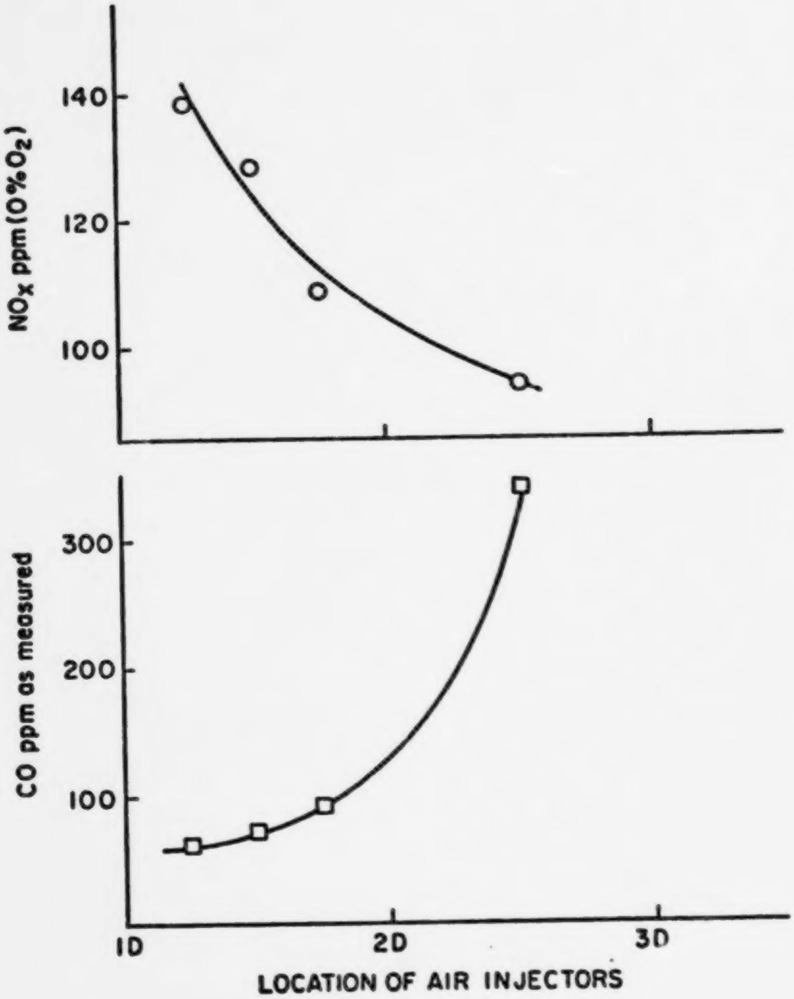


Figure 6. The Influence of the Location of Staged Air Addition on NO_x and CO Formation with 87 Percent of the Stoichiometric Air at the Burner and 4 Percent Overall Excess Oxygen

optimum location for the addition of staged air in this system is between 1.75 and 2.5 furnace diameters from the oil nozzle.

2.3 Implications of the Field Test Results

Only a selection of the results obtained during the investigations in the two package boilers have been presented in this paper. Baseline tests were carried out to establish the operating characteristics of the boilers and the emission levels appear to be typical of other units of similar size. The influence of the various NO_x control techniques has been established for both natural gas and fuel oil. Of considerably more importance than the specific results are the implications of the tests with respect to emission control from this class of equipment.

Pollutant emission control techniques for package boilers must be considered from two points of view. Control of emissions from those boilers already installed, i.e., retrofit and the control of emissions from new equipment which either requires some minor design modification or a radical change in boiler/burner design. Retrofit would be expected to have the most immediate effect upon total pollutant emissions from package boilers. One of the major conclusions that can be drawn from the field tests carried out in this investigation is that many problems can occur if retrofit becomes mandatory, which could render NO_x control expensive and/or ineffective in certain cases unless further work is carried out to optimize the total combustion system for low NO_x and high efficiency.

The boilers chosen for testing were done so with a knowledge of the requirements of the control system to be installed and yet problems were uncovered that could not have been anticipated. Changes in the geometry of the firetube boiler windbox to accommodate the flue gas recirculation inlet resulted in the initiation of severe pulsations at several boiler loads. Successive modifications succeeded in alleviating the problem but not in eliminating it. Flame instability occurred in the watertube boiler with the addition of greater than 30 percent recirculation at all boiler loads. Without prior direct experience, neither of these practical problems could be predicted. There is no reason to believe that these two boilers represent special cases and it must be expected that similar problems would occur with other units. The age of equipment and the lack of available space in the vicinity of most package boilers will tend to extend the problems of retrofit, particularly with respect to flue gas recirculation even if it were to be shown to be an effective control technique.

Based upon the results of the laboratory investigations, flue gas recirculation was as effective as could be expected in reducing NO_x emissions from the firetube boiler. However, the recirculation of flue gases cannot be considered as a cost-effective control technique for watertube boilers if the results of these tests are typical. Comparison with the data of Cato el al [7] suggested that baseline emissions from this boiler are perhaps a little lower than could perhaps be expected, but that the emission characteristics do not differ from other boilers of this size. We believe that the minor influence of flue gas recirculation on emissions is attributable to the fact that the total NO_x emission at intermediate boiler loads is produced by the oxidation of fuel nitrogen compounds. The generous furnace volume and low combustion intensity minimize thermal NO formation. Consequently, reductions in flame temperature will not significantly influence emissions. The slight increase in emission at low recirculation is probably caused by improved air/fuel mixing due to the increased burner pressure drop. It may well be that minor changes in burner design would result in an improvement in the efficiency of flue gas recirculation.

3.0 LABORATORY INVESTIGATIONS

The overriding objective of the continuing laboratory investigations is to establish the optimum combustion conditions necessary to ensure maximum thermal efficiency with minimum pollutant emissions (EPA Contracts 68-02-1498 and 68-02-1500). Having established these conditions, a combustion system will be designed, constructed and operated to demonstrate that they are compatible with the successful operation of a commercial system. It is not the intent to write a "text" on burner design or to manufacture a commercial burner, but to provide proof of the practical viability of the concepts of low emission, high efficiency oil burners for package boilers.

A burner can be described simply as a piece of equipment which allows safe conversion of chemical energy contained in a fuel into usable thermal energy. In a package boiler this requires as a minimum the creation of conditions which ensure flame stability and complete combustion without accelerating the mechanical deterioration of any of the boiler/burner components. These necessary conditions can be created by suitable hardware design to produce the optimum fuel-air-combustion product mixing patterns within the combustor. The practical choices available to the burner designer are the geometry of the burner, the method of fuel delivery and the condition of the combustion air at the burner throat. Prior to the necessity for NO_x control the major problem of ensuring complete combustion was solved by efficient fuel air mixing based upon the combustion engineers dictum that mixed is burned. However, for fuels containing bound nitrogen, rapid fuel air mixing maximizes nitric oxide production. The objective of the laboratory investigations is to determine those design options which will provide a controlled rate of fuel air mixing which will minimize NO production and yet ensure complete combustion at low overall excess air levels.

In the investigations in the field, fuel rich combustion was achieved by dividing the total air supply and injecting some part of that air at a physical location remote from the burner. In the field this exercise was more successful than the original laboratory investigations. The major problem in the laboratory was that smoke emissions increased in almost direct correspondence to the reduction of NO. Smoke emission from practical flames is the net result of excessive carbon formation and poor carbon burnout. Staging the combustion process will undoubtedly cause an increase in the mass of soot produced, and therefore, it is essential that optimum conditions for carbon burnout are provided after injection of the second stage air. Lee, Thring and Beer [8] showed that in the temperature range 1300-1700°K the rate of carbon combustion in gm/cm^2 of soot surface can be represented by

$$q = 1.085 \times 10^4 \rho_{O_2} T^{-1/2} \exp(-39300/RT) \qquad (1)$$

where

ρ_{O_2} is the partial pressure of oxygen (atm)

T is the temperature (°K)

R is the universal gas constant (cal/mole°K)

Equation (1) illustrates the importance of both oxygen concentration and temperature on the rate of soot burnout. Consequently, even without increased soot formation, soot emissions will increase with staged combustion if the second stage air is mixed with the carbon when temperatures are too low or the addition of the staged air chills the flame products.

In the laboratory investigations it was found that NO emissions were relatively insensitive to the level of staging when the second stage air was injected from the combustor axis [5]. If the second stage air was added either from the axis or from the combustor walls too close to the burner NO emissions increased. Species concentration maps have been obtained for certain burner conditions in an attempt to explain the performance of the modified commercial burner used in the Phase II laboratory investigations. The samples were withdrawn from the flame with a cooled stainless steel probe. Figure 7 shows a schematic layout of the combustor illustrating the relative position of the fuel injector, the air streams and the sampled field, and Table 1 lists the burner conditions for the tests which will be discussed in this paper and O_2, CO and NO concentration contours are shown in Figures 8, 9 and 10. The burner used in these investigations has been described in detail by Muzio [5]. It was a commercial burner which was modified slightly to provide independent control of the air distribution in the primary and secondary streams. The original combustion air damper was retained to vary the swirl intensity of the secondary stream.

The "baseline" conditions for the laboratory investigations correspond to Test 3, the combustion air is split equally between the primary and secondary flows. Figure 11 compares O_2, CO and NO concentration profiles at the exit of the burner divergent (x/D = 0.45) for the unstaged baseline case and a staged flame, Test 6. In Test 6, 20 percent of the total air flow was added downstream of the burner through sidewall injectors while maintaining the 50:50 split between the primary and secondary air flows at the burner. The most remarkable feature of the unstaged profiles is the high axial oxygen concentration (almost pure air) so remote from the burner throat. This suggests that the ignition front is situated well downstream of

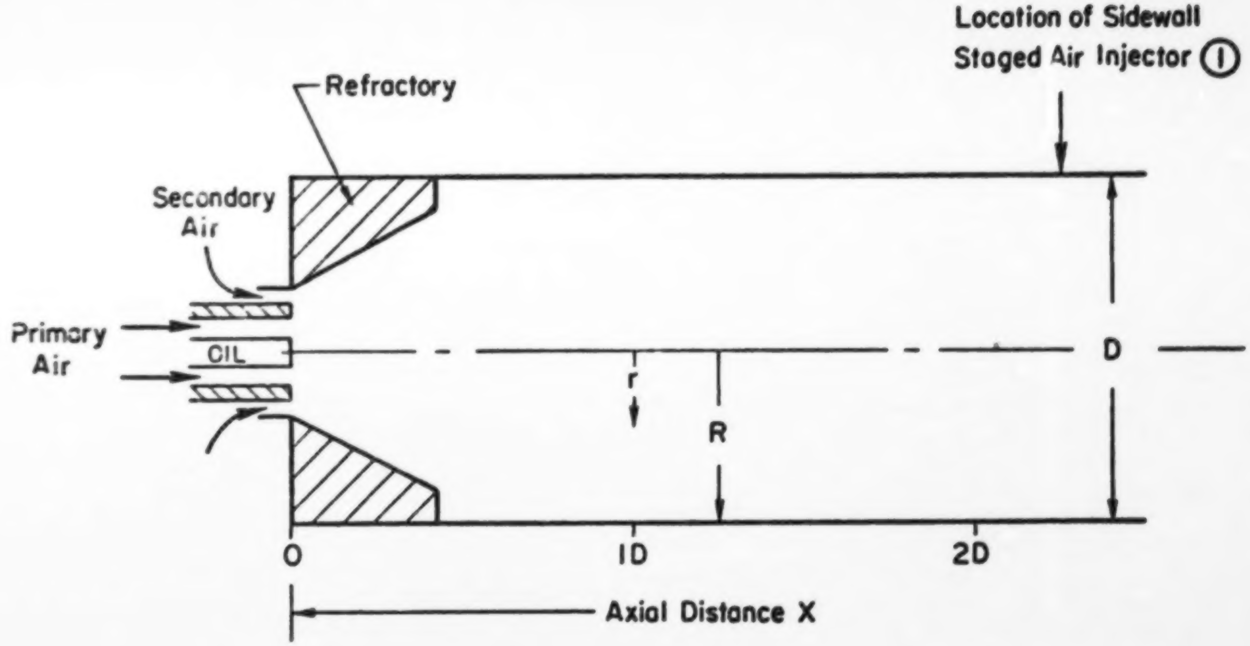

Location of Sidewall
Staged Air Injector ①
Refractory
Secondary
Air
Primary
Air
OIL
r
R
D
0
1D
2D
Axial Distance X

Figure 7. Schematic Layout of Laboratory Combustor Showing the Location of Sidewall Staged Air Injectors and the Burner Geometry

Table 1. Test Conditions for Modified Commercial Burner

Test No.	Heat Input 10^6 Btu/hr	Excess Air %	P/s Air Ratio Volume/Volume	Atomization Press. psi	% Staged x/D = 2.2	Flue Gas		Nozzle Capacity
						NO	Smoke	
3	3.4	17	50/50	20	-	273	4 1/2	80 gph
4	3.4	17	50/50	28	-	240	4	
6	3.4	17	50/50	20	20	218	8 1/2	
8	3.4	17	50/50	22	-	288	3	100 gph

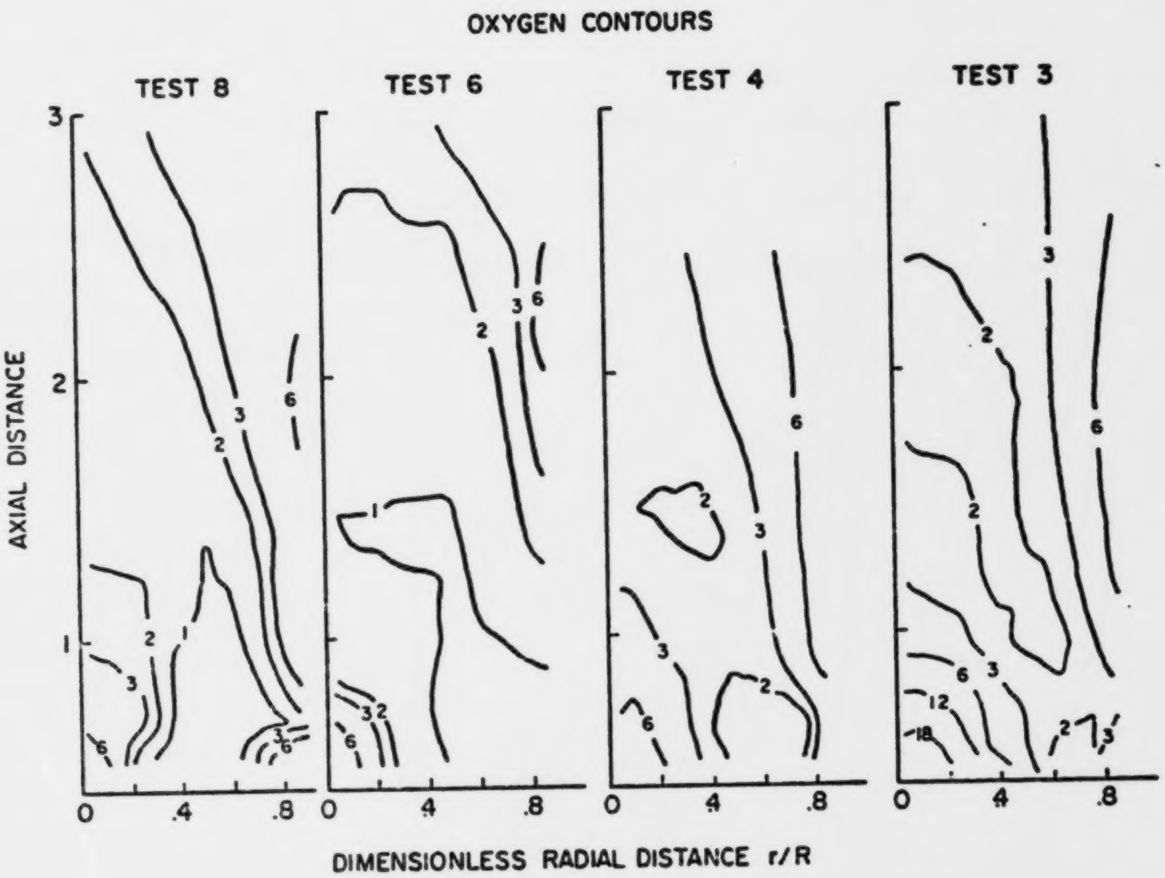
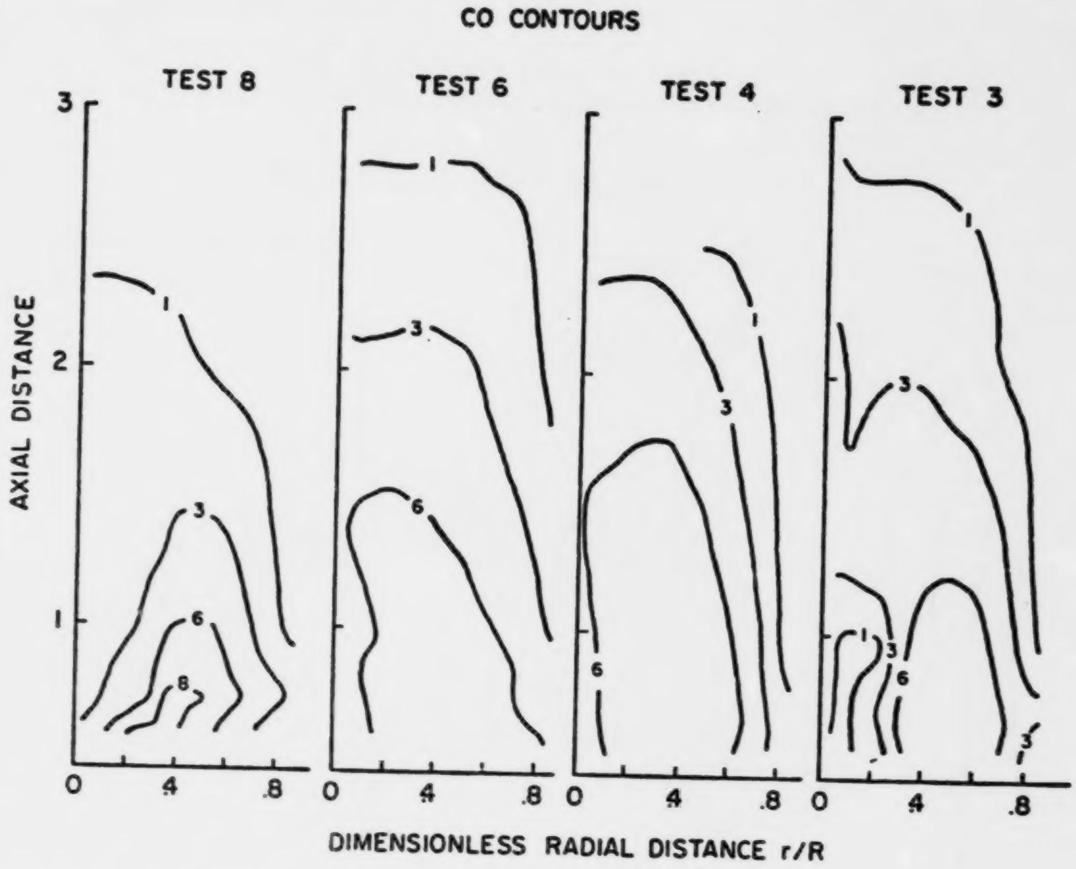


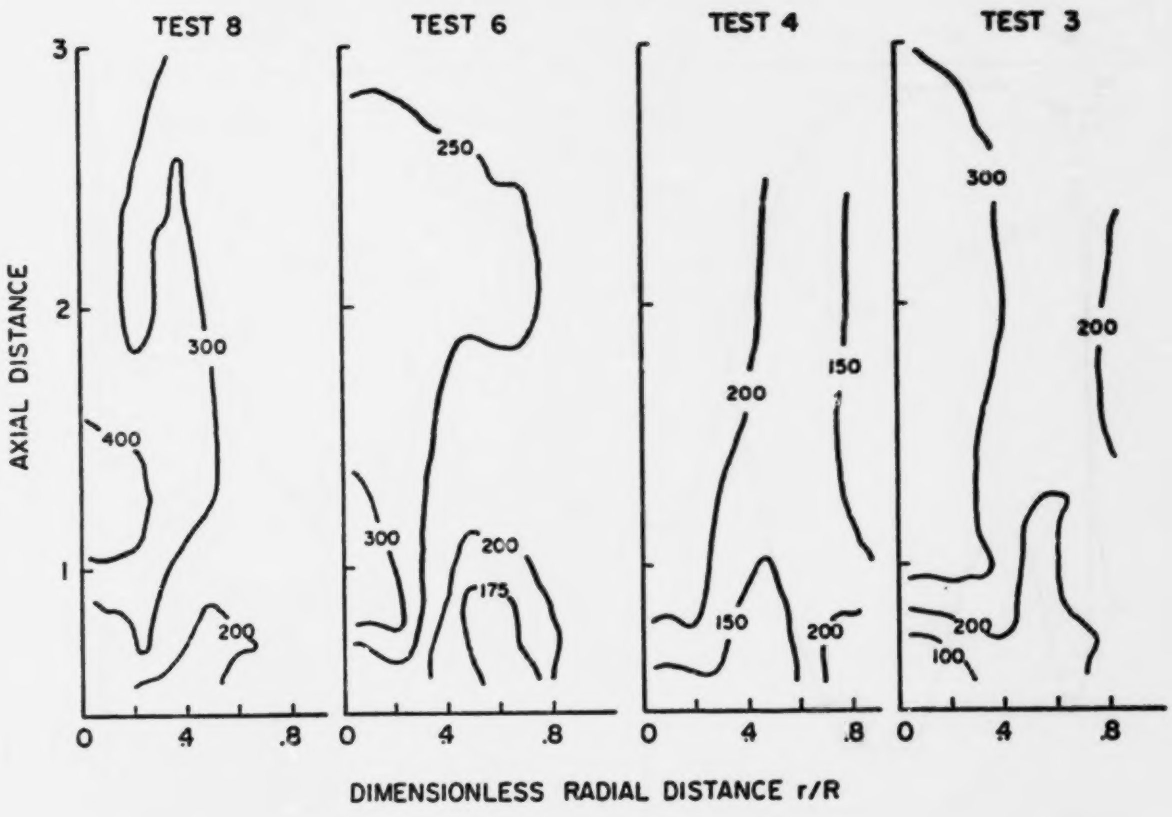
Figure 8. Laboratory Combustion Measured Oxygen Contours
(Test Conditions Given in Table 1)



CO CONTOURS

TEST 8 TEST 6 TEST 4 TEST 3

Figure 9. Measured Carbon Monoxide



NO CONTOURS

Figure 10. Measured Nitric Oxide

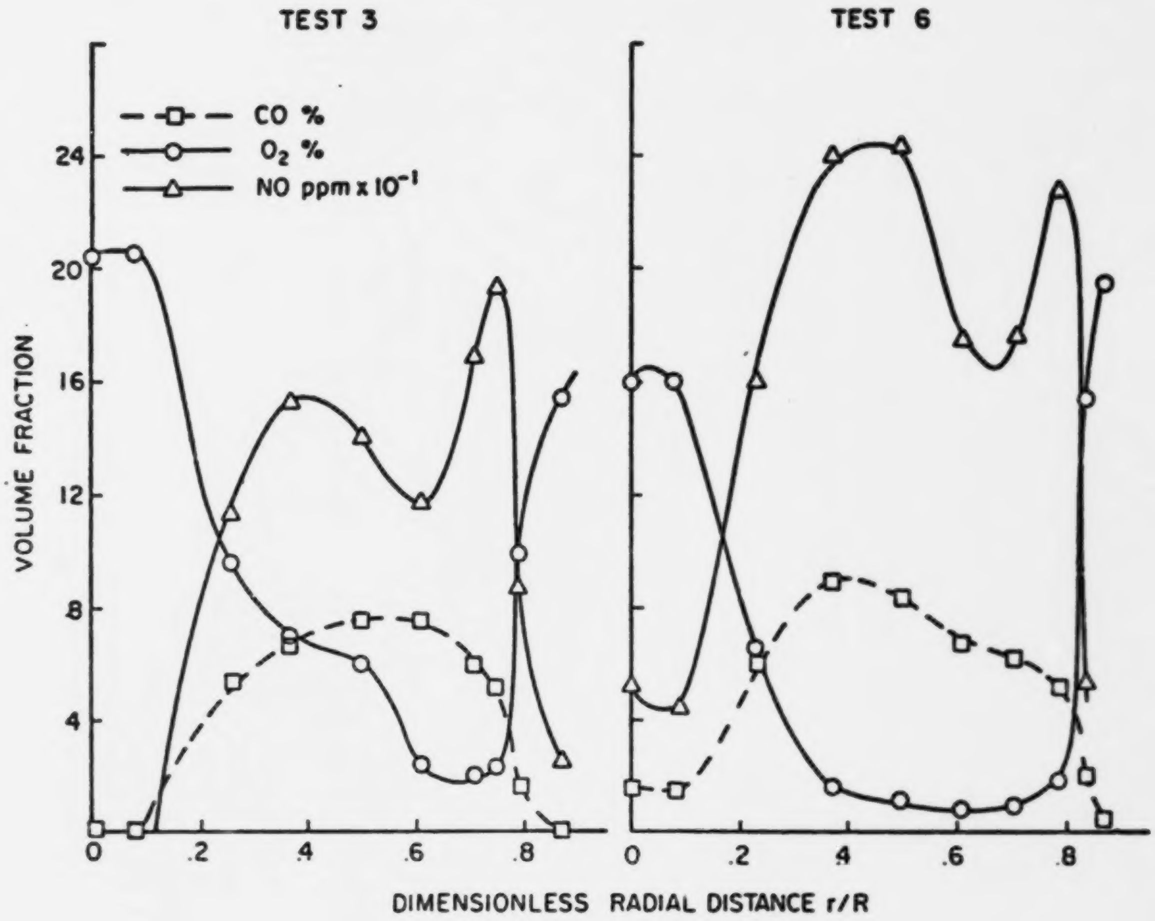


Figure 11. Radial Distribution of O_2, CO and NO at x/D = 0.45

the fuel nozzle and that the primary air hardly participates in the combustion process to that point. Muzio et al [5] reported that increasing the swirl intensity by changing the position of the secondary air damper had almost no influence on pollutant emissions. Species measurements indicated that the mixing process was almost unaffected by the position of this damper, e.g., the axial oxygen concentration was independent of "swirl level". The primary effect of reducing the combustion air flow through the burner throat in Test 6 appears to be to slightly increase the carbon monoxide concentrations and to reduce the axial oxygen concentration. Reduced throat velocities may well allow the ignition front to move upstream closer to the axis, thus consuming more of the primary air.

Figures 11 and 12 emphasize the fact, that in the initial stages of heat release, the major difference between the staged and unstaged flames is the participation of the primary air stream in the combustion process. Figure 12 plots the radial distribution of three derived properties: N, the degree of oxidation, M the stoichiometric mixing factor, and K the mass of NO produced per mass of carbon. These properties are defined as:

$$N = \frac{\text{mass of reacted oxygen}}{\text{mass of reacted oxygen plus mass of oxygen necessary to complete reaction}}$$

$$M = \frac{\left(\frac{\text{mass of oxygen}}{\text{mass of fuel}}\right)_{\text{flame point}}}{\left(\frac{\text{mass of oxygen}}{\text{mass of fuel}}\right)_{\text{stoichiometric}}}$$

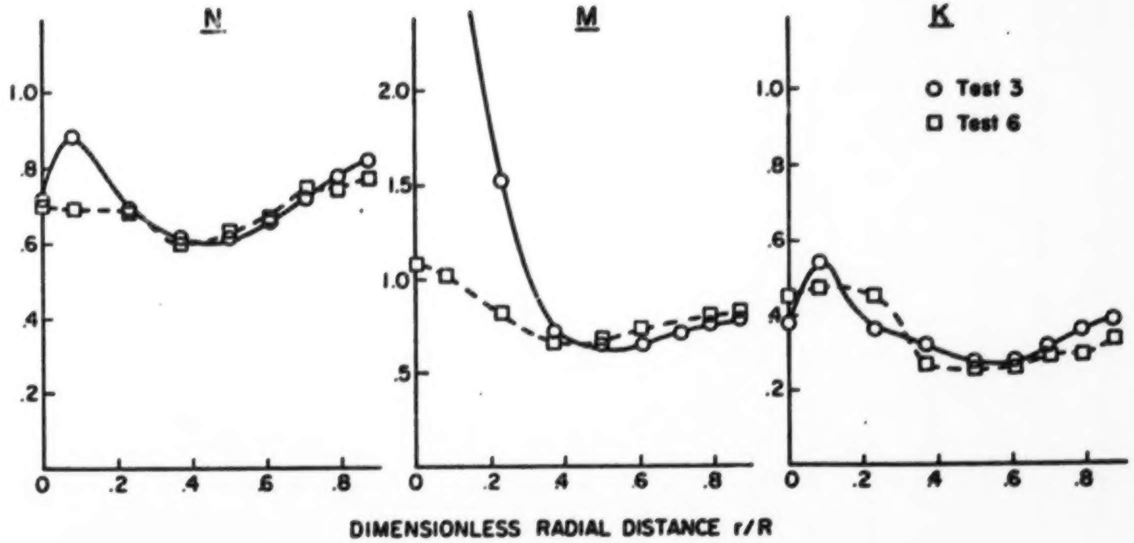


Figure 12. Radial Distribution of Derived Flame Properties at x/D = 0.71

$$K = \frac{\text{mass of NO}}{\text{mass of fuel reacted } (CO + CO_2)}$$

A more detailed account of the calculation of these quantities from flame data has been given by Hemsath [9]. It should be noted that these derived quantities relate to time average values. When N = 1 combustion is complete and values less than 1 give an indication of the completeness of reaction at that point. In a perfectly mixed situation (assuming mixing controlled heat release) N would be equal to 1 whenever M = 1. M = 1 indicates that the fuel and oxygen are present in stoichiometric proportions.

Over a large proprotion of the radial field at x/D = 0.71 the degree of oxidation is similar for the staged and unstaged flames; however, the bulk of the unreacted fuel shown by the carbon monoxide concentration contours presented in Figure 9 lies off the axis and in this region the degree of fuel air mixing, as shown by M, is almost the same for the staged and unstaged flame. This is only true if the unmixedness of the two conditions is similar, M = 1 could occur and the unmixedness be such that at some instant in time there could either be all fuel or no fuel, and the two would never be mixed on a molecular scale.

Test 6 with 20 percent staging showed a reduction in flue gas NO emission of only 18 percent compared to the baseline level. At the exit of the divergent and at x/D = 0.71, actual NO concentrations are higher for the staged case than the unstaged case (see Figures 11 and 13) but the mass of NO per mass of fuel reacted is very similar (see Figure 12).

It is contended that the method of second stage air injection should satisfy the following criteria:

- reaction of fuel nitrogen intermediates should be complete, otherwise the addition of air will allow the formation of fuel NO;
- rapid mixing of the staged air and the primary products should take place to give the maximum opportunity for carbon burnout.

Second stage air was injected at $x/D = 2.2$ in Test 6 by which time reaction was almost 80 percent complete and the unreacted fuel was concentrated toward the axis of the combustor (see Figure 14). The sidewall injectors were constructed to promote swirling second stage air flow [5]. This construction directed the air jet away from the axis of the combustor. Thus the air jets never penetrated to the combustor axis where the bulk of the unburned fuel lay. Mixing between the second stage air and the partially combusted products of the primary zone was poor. Axial oxygen concentrations shown in Figure 15 for two radial locations graphically illustrates this point. Because combustion was almost 80 percent complete by $x/D = 2.2$, it was concluded that improved mixing of the staged air would have no influence upon NO emissions but that smoke emissions might well be reduced. Consequently, minor modifications were made to the sidewall injectors to test this hypothesis.

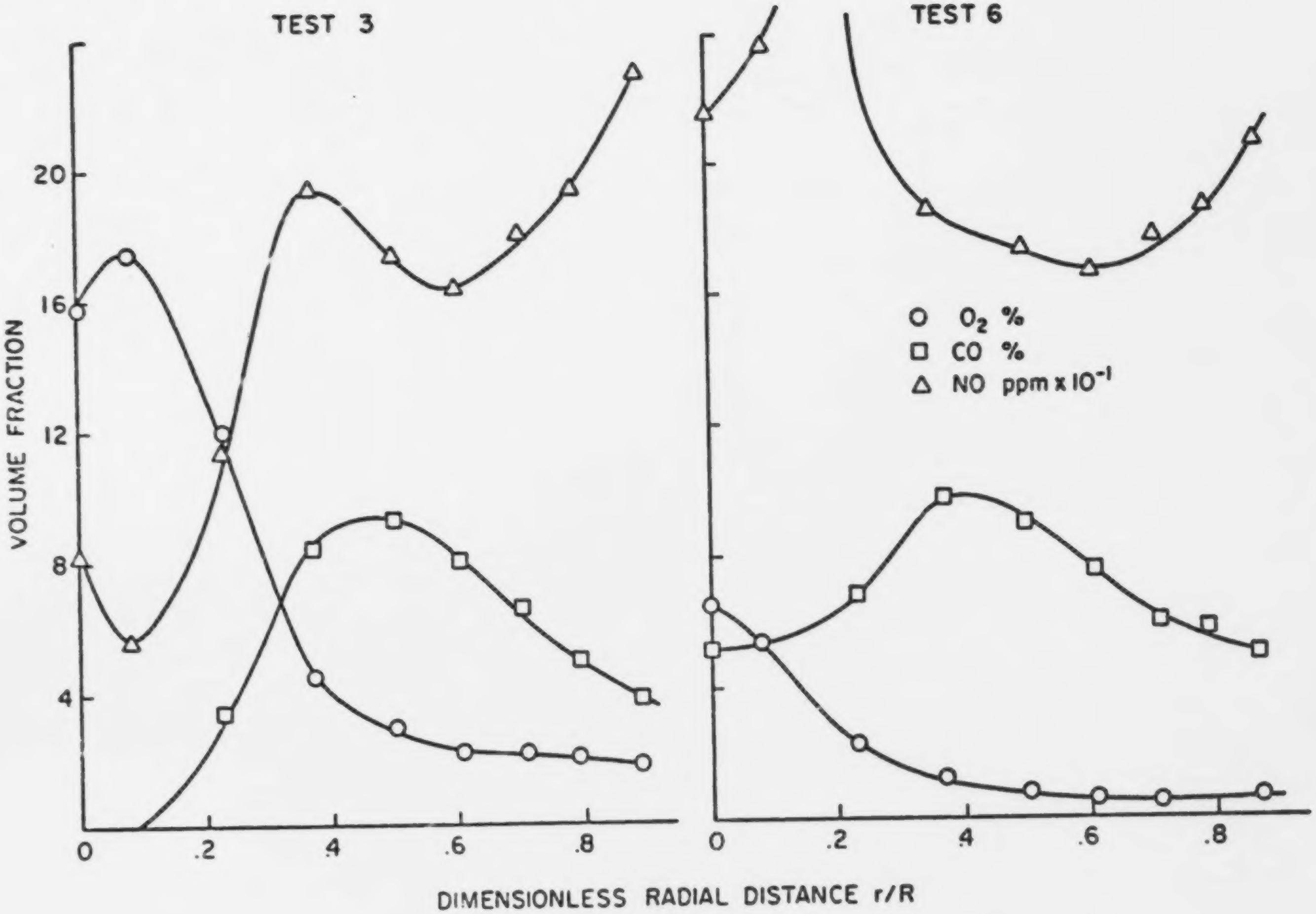


Figure 13. Radial Distribution of O_2, CO and NO at x/D = 0.71

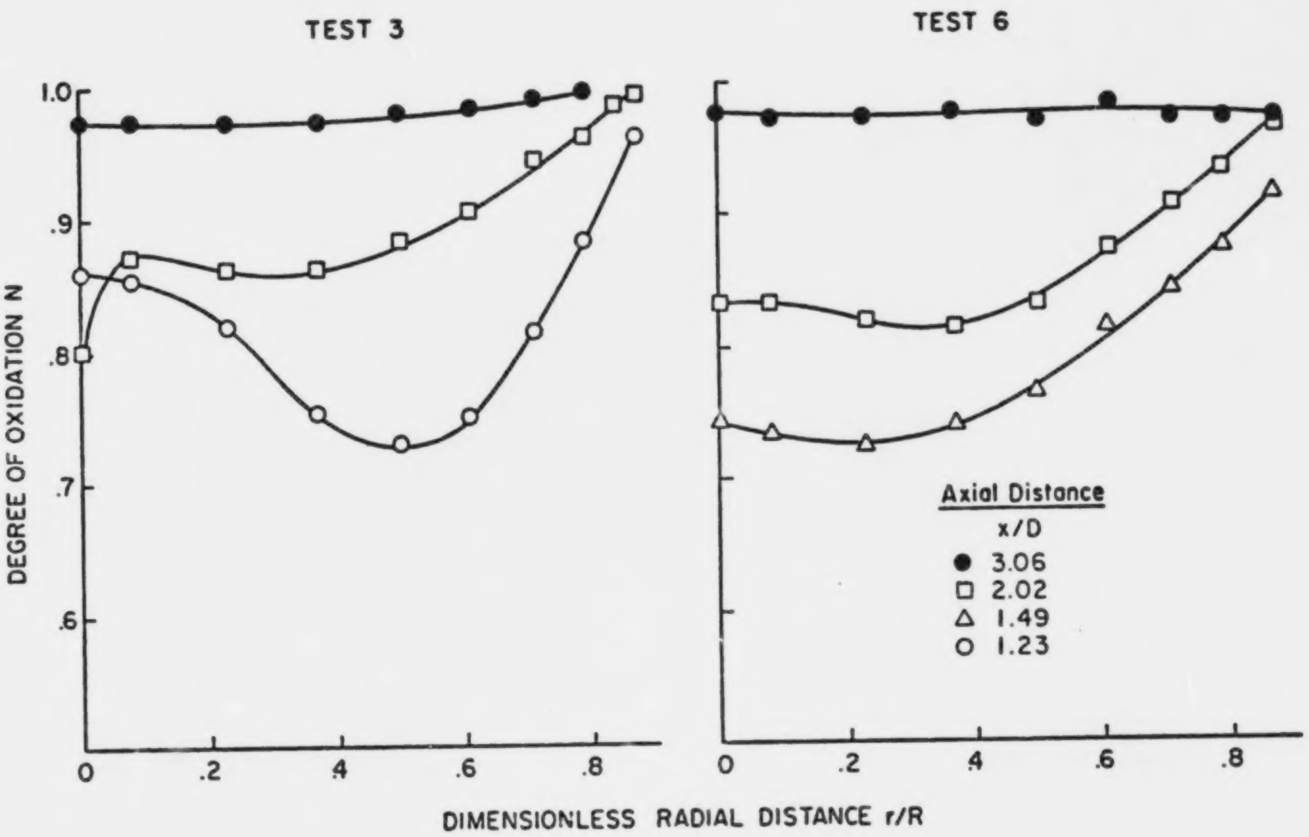


Figure 14. Radial Distribution of Degree of Oxidation at Various Axial Locations for a Staged and Unstaged Flame

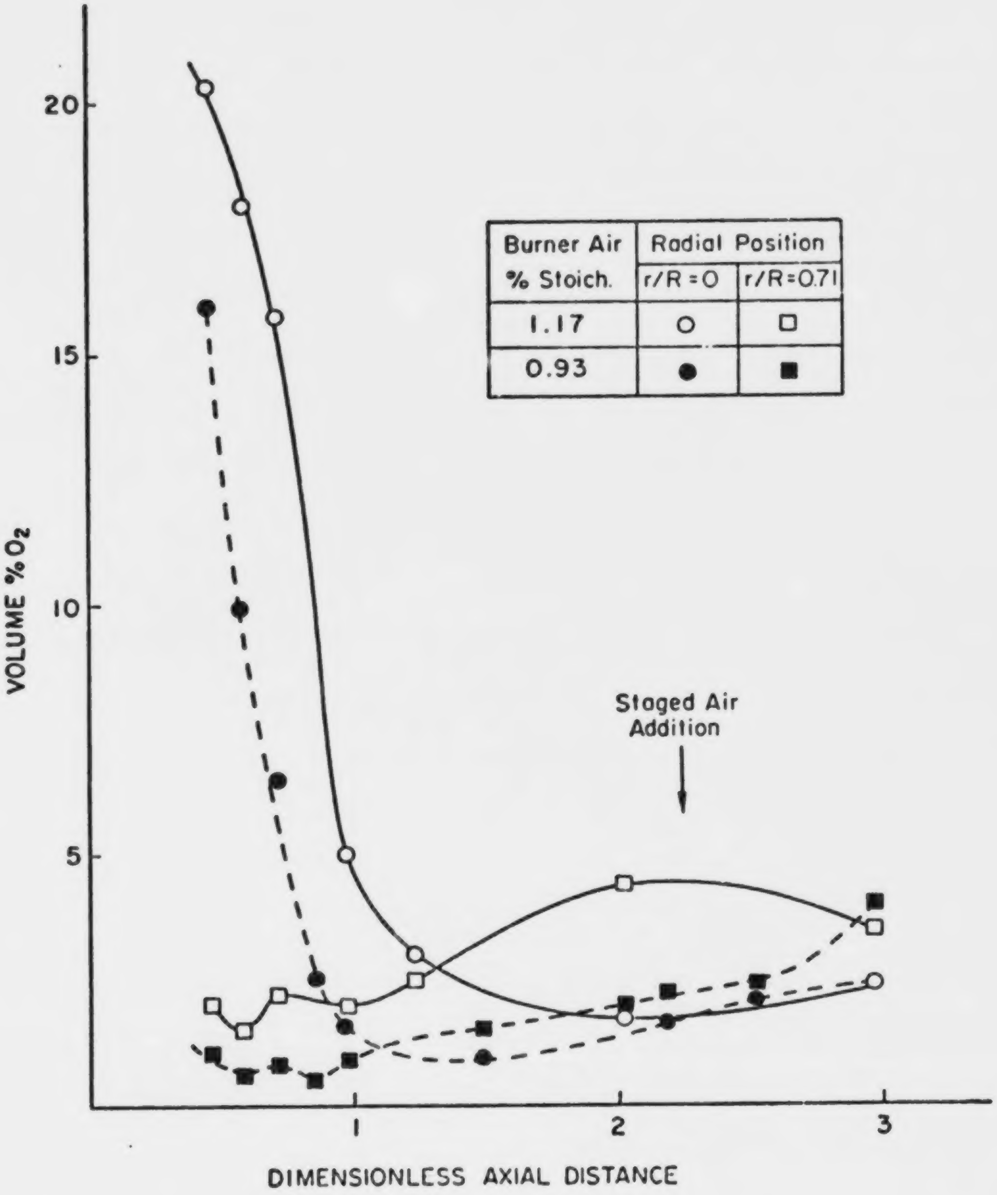


Figure 15. Axial Distribution of O_2 Concentration at r/R = 0 and 0.71 for Test 3 and Test 6

New sidewall injectors were constructed to inject the staged air directly toward the combustor axis and Table 2 compares emissions with the old and new injector designs for various staging levels and injection locations. With only 20 percent of the total air added through the staging injectors, the design of the injector had no effect upon the NO emission. However, for the two cases where the injection took place close to the burner, smoke emissions were reduced. When 40 percent of the air was staged, then both the smoke and NO emissions were influenced by the injector design. With the new injector design NO emissions were higher when 20 of the 40 percent staging air was added at x/D = 2.2.

After consideration of the results of these laboratory investigations the staging system for the field tests was designed with radial staged air injection. The number of injection points was also increased from four to eight in order to promote mixing. An attempt was also made to prevent flame products from impinging upon the firetube walls, which would cause local chilling.

Several measures were taken to try to influence the mixing conditions in the new burner field in order to improve staging performance using the sidewall injectors. These measures included varying the atomizing fluid from air to steam, varying the pressure of the atomizing fluid , air distribution across the throat, nozzle size and swirl distribution at the burner throat. The objective at this time was merely to demonstrate that staging could be more

Table 2. The Influence of Method of Staged Air Injection Upon Pollutant Emissions

Percentage of Total Air Added Through Sidewall Injectors			NO ppm as Measured		Smoke No. Bacharach Scale	
$\frac{x}{D} = 2.2$	$\frac{x}{D} = 2.6$	$\frac{x}{D} = 3.52$	Old Design	New Design	Old Design	New Design
20	-	-	207	212	4	3
-	20	-	194	200	5	3 1/2
-	-	20	166	160	8	8
-	20	20	161	152	8	6 1/2
20	20	-	166	189	7	5

17 Percent Excess Air

Heat Input 3.4×10^6 Btu/hr

effective than had been demonstrated earlier and to try to approach the results reported by Siegmund and Turner [10]. Figures 16 and 17 illustrate some of the efforts made to minimize both NO emissions and smoke. For a given atomizing air pressure the minimum NO emissions appeared to occur between 20 and 40 percent primary air. Staging was most effective at low primary air flow rates. The best results (i.e, low NO, low smoke) were achieved by fitting a 15° vane swirler to the oil nozzle to rotate the primary air in the opposite sense to that imposed on the secondary air by the damper. 45 percent reductions in NO emissions from the "baseline" conditions with a smoke increase of 1.5 on the Bacharach scale to 5.5. Even so, this cannot be considered as satisfactory performance.

The emission performance of the modified commercial burner was found to be very sensitive to atomization parameters:

- Nozzle size - Figures 18 and 19 illustrate that although the trends were similar, smoke and NO_x emissions as a function of primary air percentage are dependent upon the capacity of the oil nozzle at a given firing rate.
- Atomization fluid - Figure 20 illustrates the effect of changing from air to steam as the atomizing fluid on NO_x and smoke.

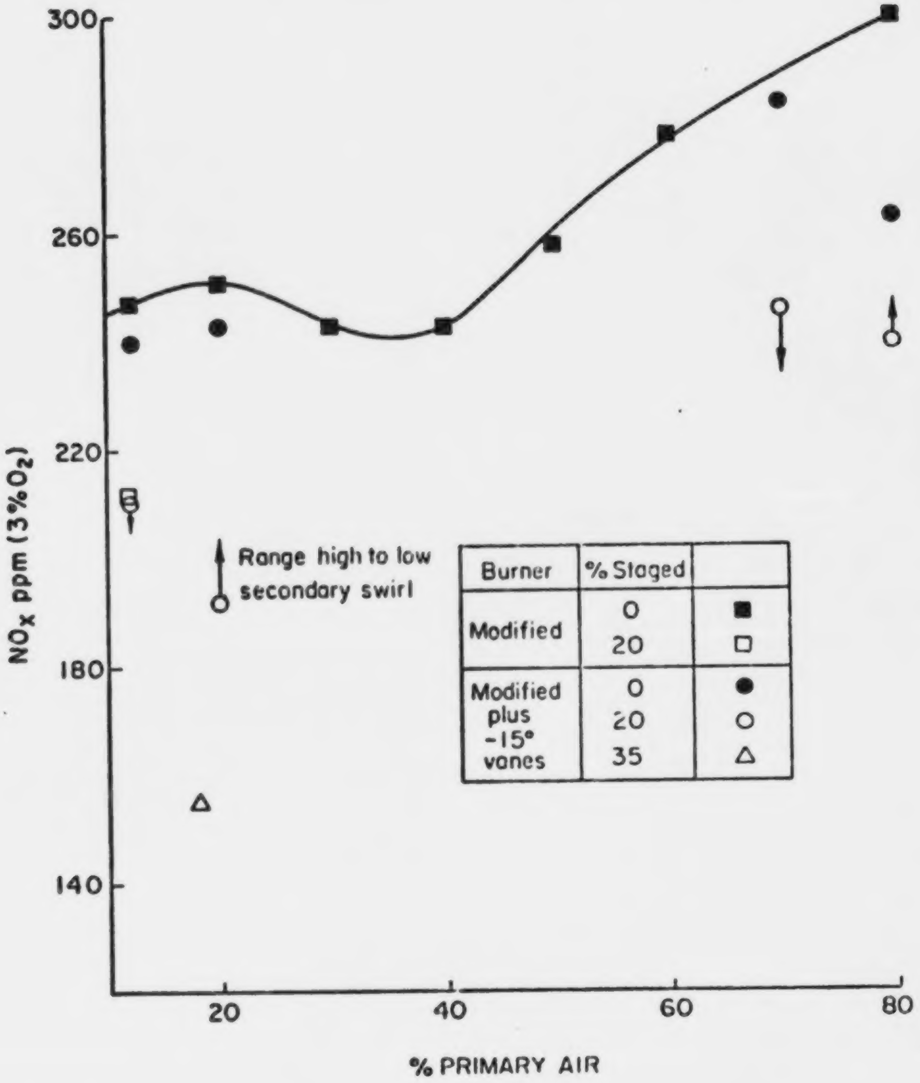


Figure 16. The Influence of Primary Air Percentage and Swirl Level on NO Emissions (17 Percent Excess Air 3.4×10^4 Btu/hr Heat Input)

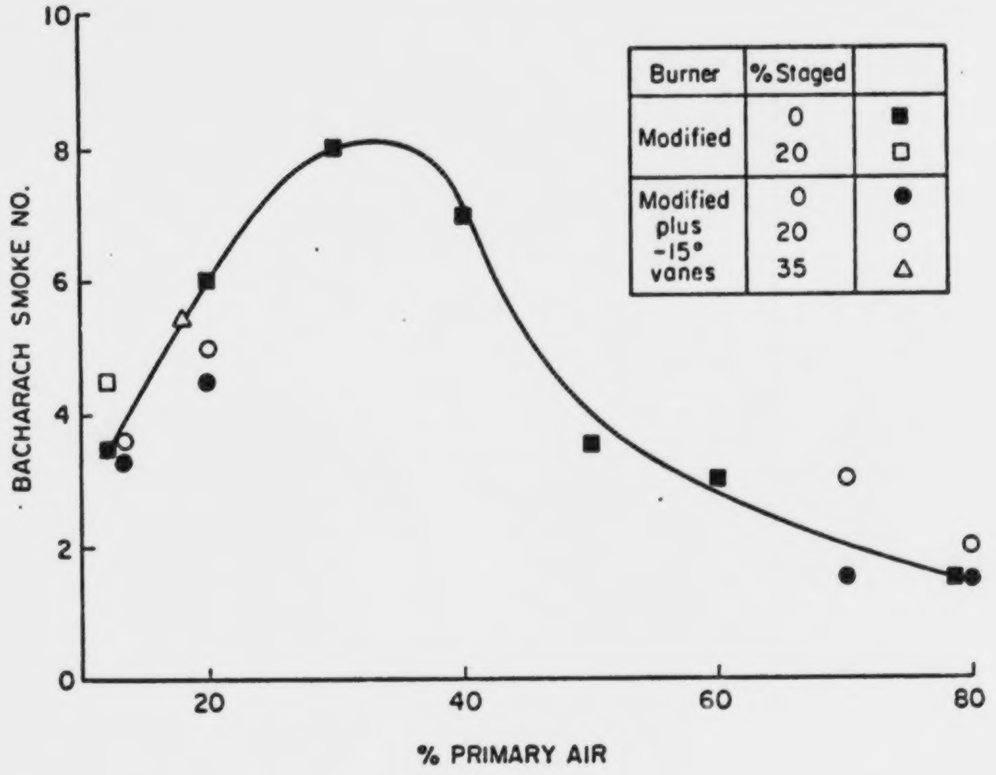


Figure 17. The Influence of Primary Air Percentage and Swirl Level on Smoke Emissions (17 Percent Excess Air 3.4 x 10^4 Btu/hr Heat Input)

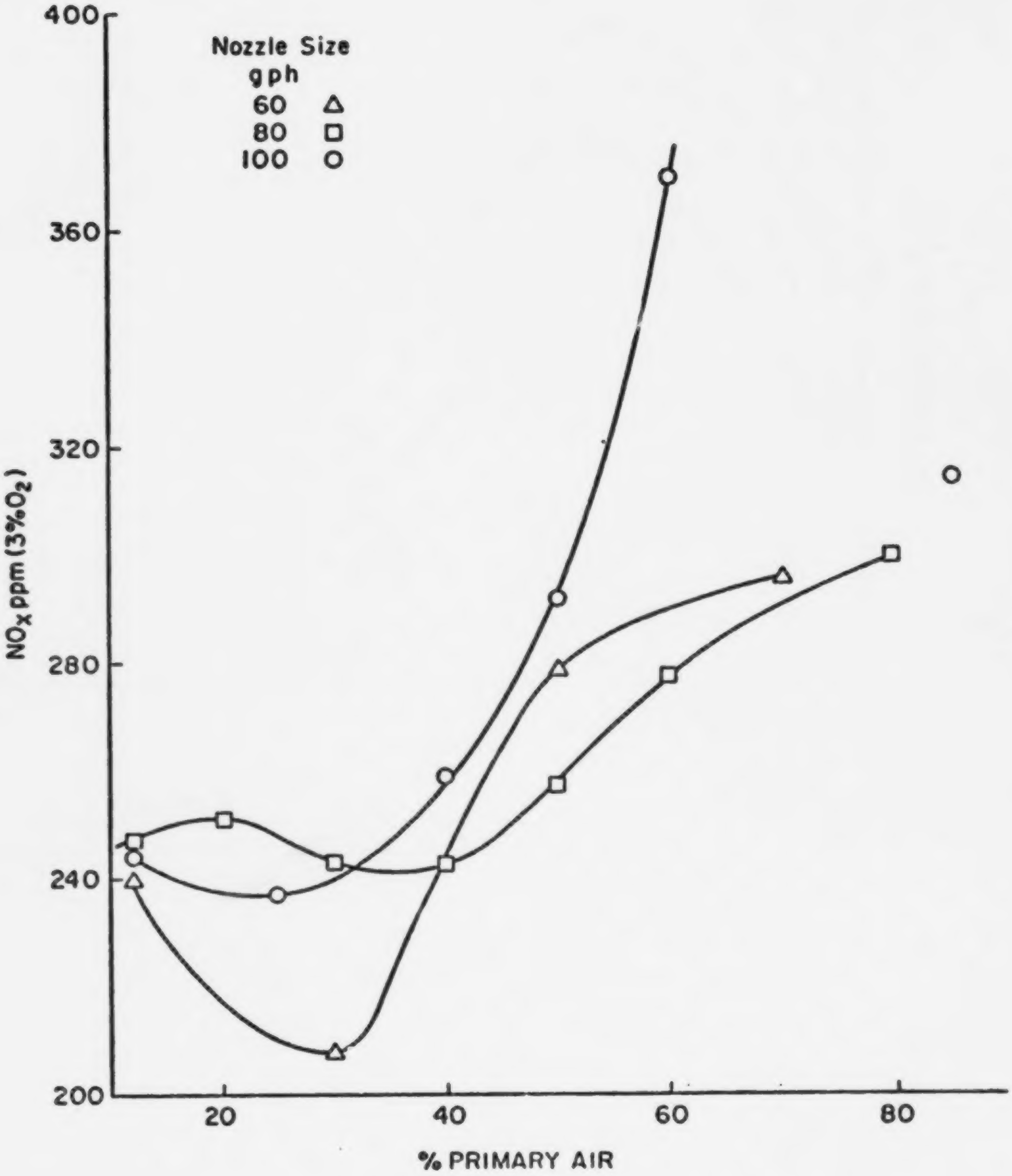


Figure 18. The Influence of Primary Air Flow and Nozzle Size on NO_x Emissions from Fuel Oil Flames (3.4×10^6 Btu/hr 17 Percent Excess Air)

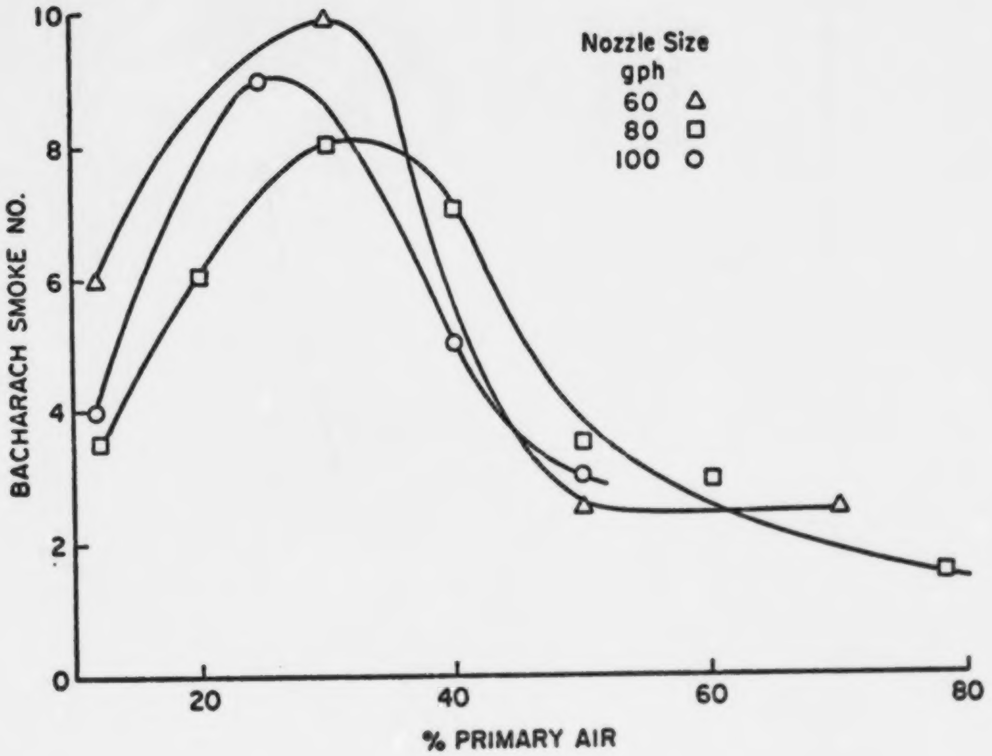


Figure 19. The Influence of Primary Air Flow and Nozzle Size on Smoke Emissions from Fuel Oil Flames (3.4×10^6 Btu/hr 17 Percent Excess Air)

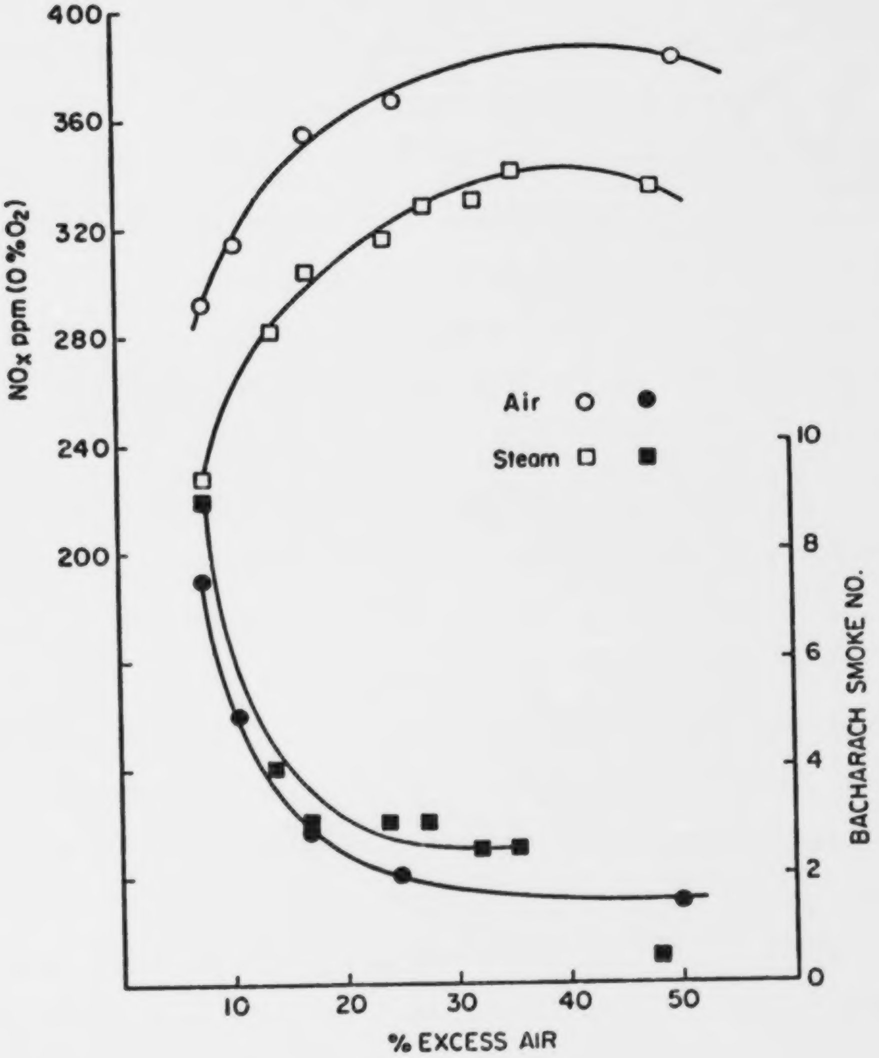


Figure 20. NO_x and Smoke Emissions as a Function of Excess Air Level and Atomization Medium

- Pressure of the atomizing fluid - it had previously been reported [5] that increasing the air pressure and therefor the mass flow of atomizing air decreased emissions. The results presented in Figure 21 show that this trend holds for larger nozzle sizes and for steam atomization.

The reasons for the observed emission characteristics for steam are not known. However, species concentration maps give an indication why increased atomization pressure and nozzle size affect the pollutant emissions.

Comparing the iso-concentration contours shown in Figures 8, 9, and 10 for Tests 3, 4, and 8, it is apparent from the oxygen contours that the fuel air mixing process is strongly dependent upon the oil nozzle parameters. Increasing the pressure from 20 to 28 psig produces more fuel rich conditions in the initial stages (see the CO contours). Changing the size of the oil tip has a much more radical influence on the concentration fields close to the burner nozzle (see Figures 21 and 22).

The investigations with the modified commercial burner served to emphasize the strong dependence of pollutant formation in practical flames on those parameters which control fuel air mixing processes. The burners used in the laboratory investigation and the field test were of different design and therefore it should not be expected that optimum staging conditions defined in the laboratory would also apply to the field boilers. Consequently, there is an urgent need

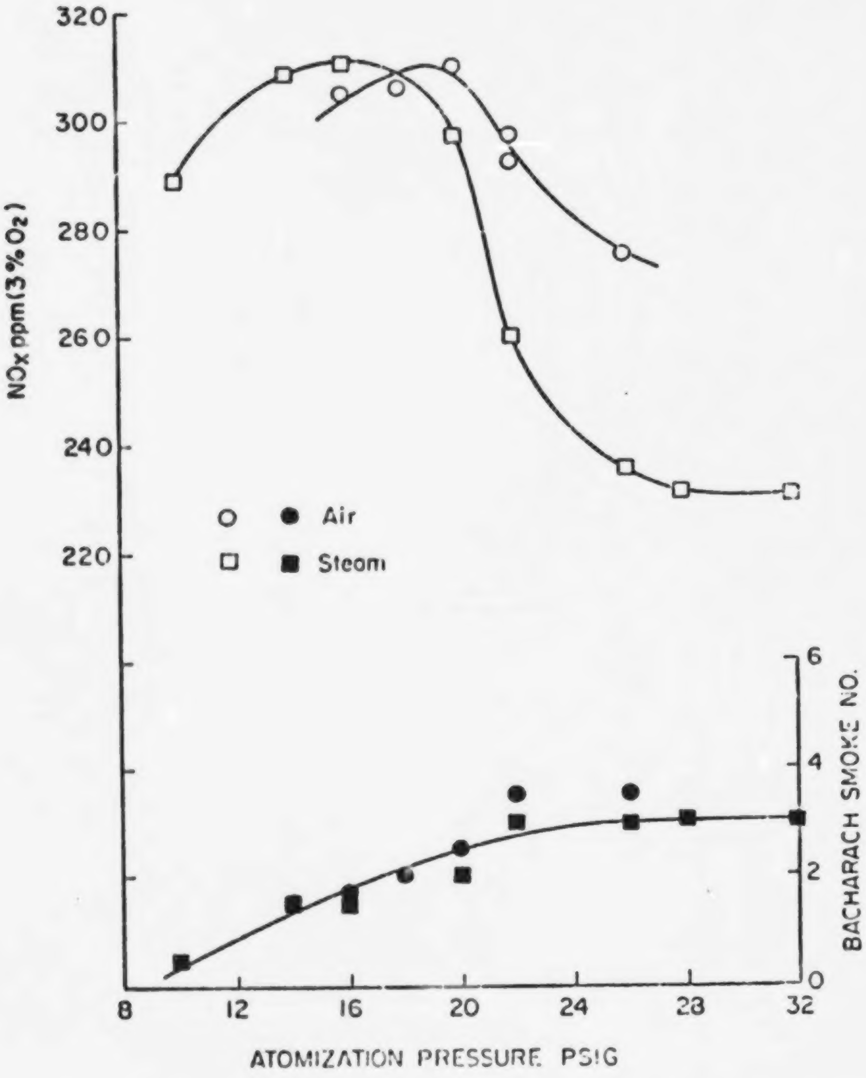


Figure 21. The Influence of Atomization Fluid and Pressure Pollutant Emissions from Oil Flames (17 Percent Excess Air, 3.4 x 10^6 Btu/hr)

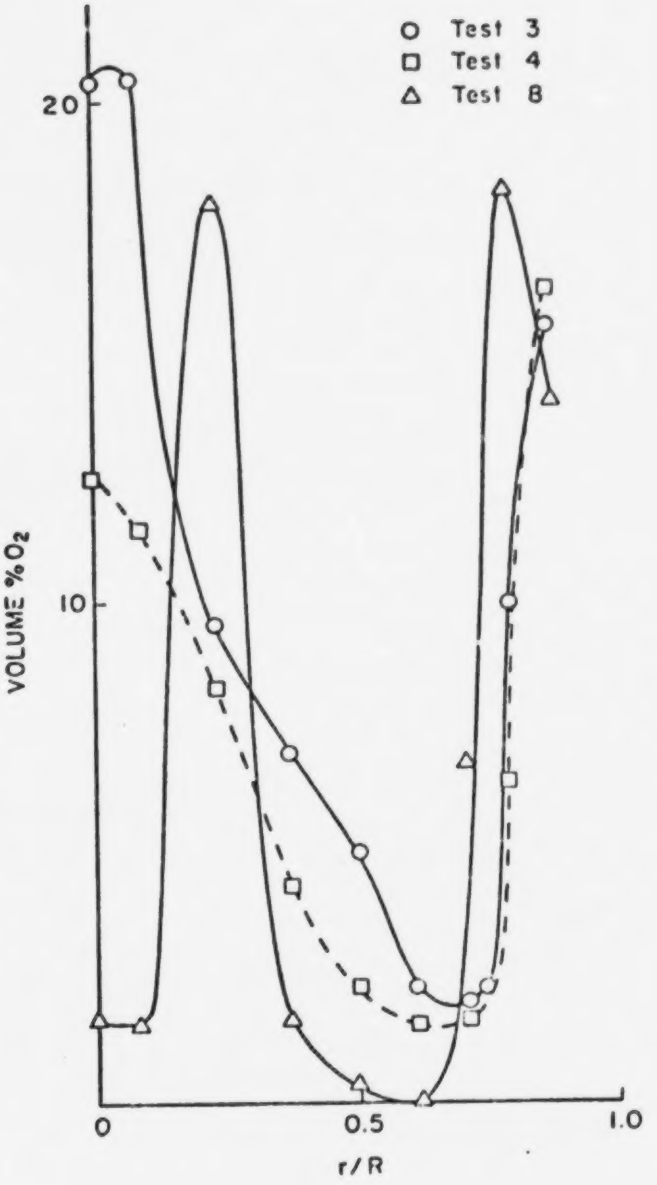


Figure 22. The Influence of Atomization Parameters on Radial Oxygen Distribution at x/D = 0.45

for experiments to define optimum mixing patterns before devising the most practical approach to produce them in staged combustion situations.

As part of the initial stage in the production of this type of information a versatile test burner has been constructed which allows the distribution of both axial and tangential velocity across the throat of the burner to be varied continuously. The air delivery system consists of four separate plenum chambers which deliver air to four annualar channels. Details of this test burner are shown in Figure 23. Rotation is imparted to each of the air streams by varying the inclination of the air nozzles and rotation in a clockwise or counterclockwise sense is possible.

It is known that the characteristics of swirling flames are dependent upon the size and intensity of internal recirculation zones [1]. The static pressure field generated by the swirling flow strongly influences both of these properties. The radial distribution of static pressure P_s is given by

$$\frac{d\ P_s}{dr} = \rho \frac{W^2}{r} \qquad (2)$$

where

ρ is density

W is tangential velocity

r is radius

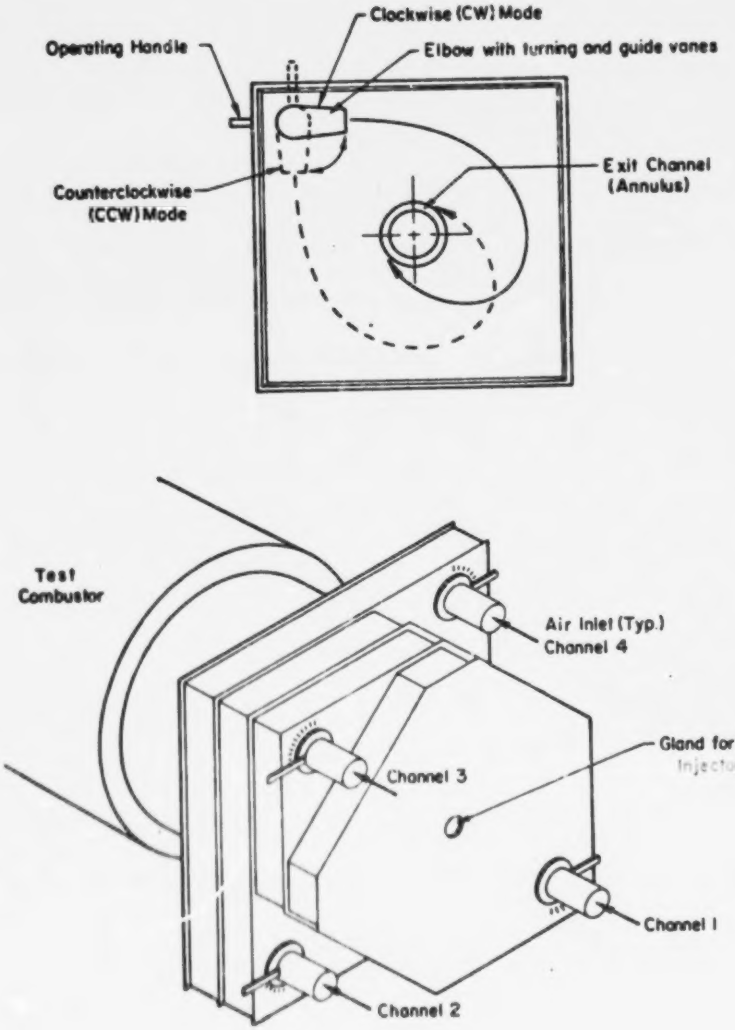

Clockwise (CW) Mode
Operating Handle
Elbow with turning and guide vanes
Counterclockwise (CCW) Mode
Exit Channel (Annulus)
Test Combustor
Air Inlet (Typ.) Channel 4
Gland for Fuel Injector
Channel 3
Channel 1
Channel 2

Figure 23. Multichannel Continuously-Variable-Swirl Test Burner

Consequently, the distribution of static pressure can be varied by controlling the radial variation of tangential velocity at the burner throat. The multichannel test burner allows the distribution of tangential velocity to be varied. With rotation on the inner of the four channels the tangential velocity distribution approaches that of a free vortex, i.e., $W = C/r$. Conversely, distribution given by $W = c'r$, solid body rotation can be produced by applying rotation to the outer channels.

Figures 24 and 25 present initial results from this investigation. NO_x emissions are plotted against the dimensionless swirl parameter S_p for two different size steam atomized nozzles. S_p is given by

$$S_p = \Sigma S_n$$

where S_n is the swirl number associated with the flow in each channel

$$S_1 = \frac{G_{\varphi_1}}{G_{x_1} r_1}$$

where

G_φ is the axial flux of angular momentum

G_x is the axial flux of linear momentum

r is the outer radius of that channel

and subscription 1 refers to channel 1.

The results presented in Figure 24 and 25 were obtained with a refractory parallel burner exit. S_p is independent of air

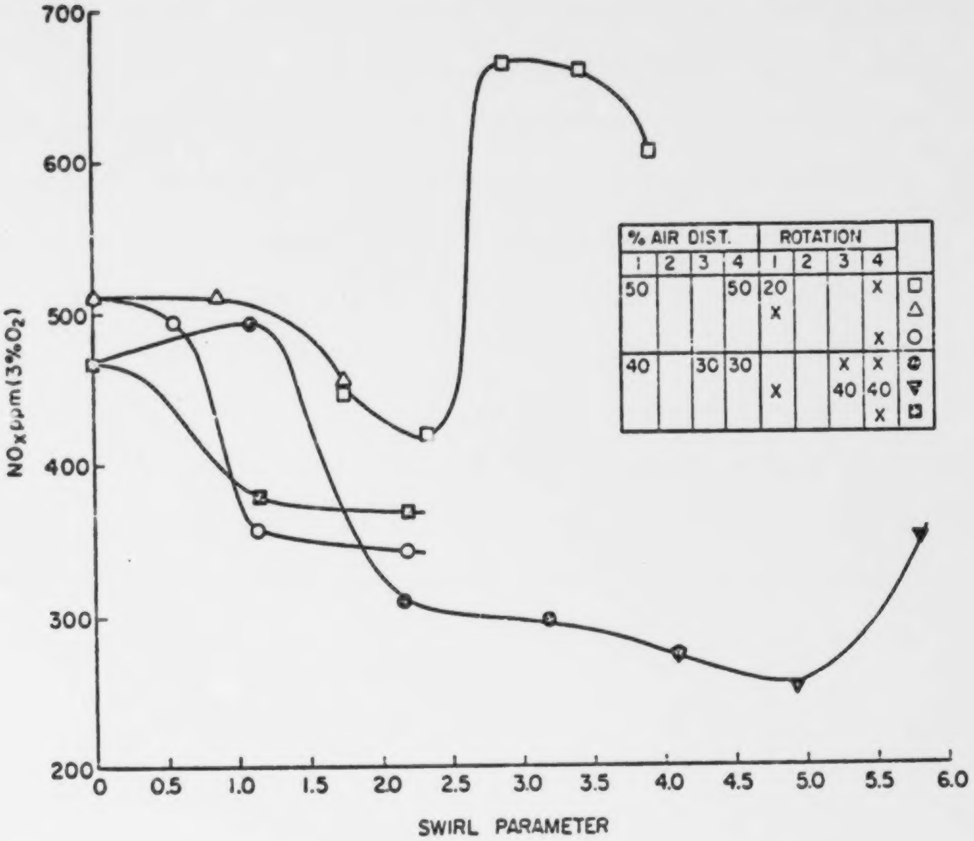


Figure 24. The Influence of Tangential Velocity Distribution on NO Emissions from Oil Flames (3 x 10^6 Btu/hr 60 gph Nozzle)

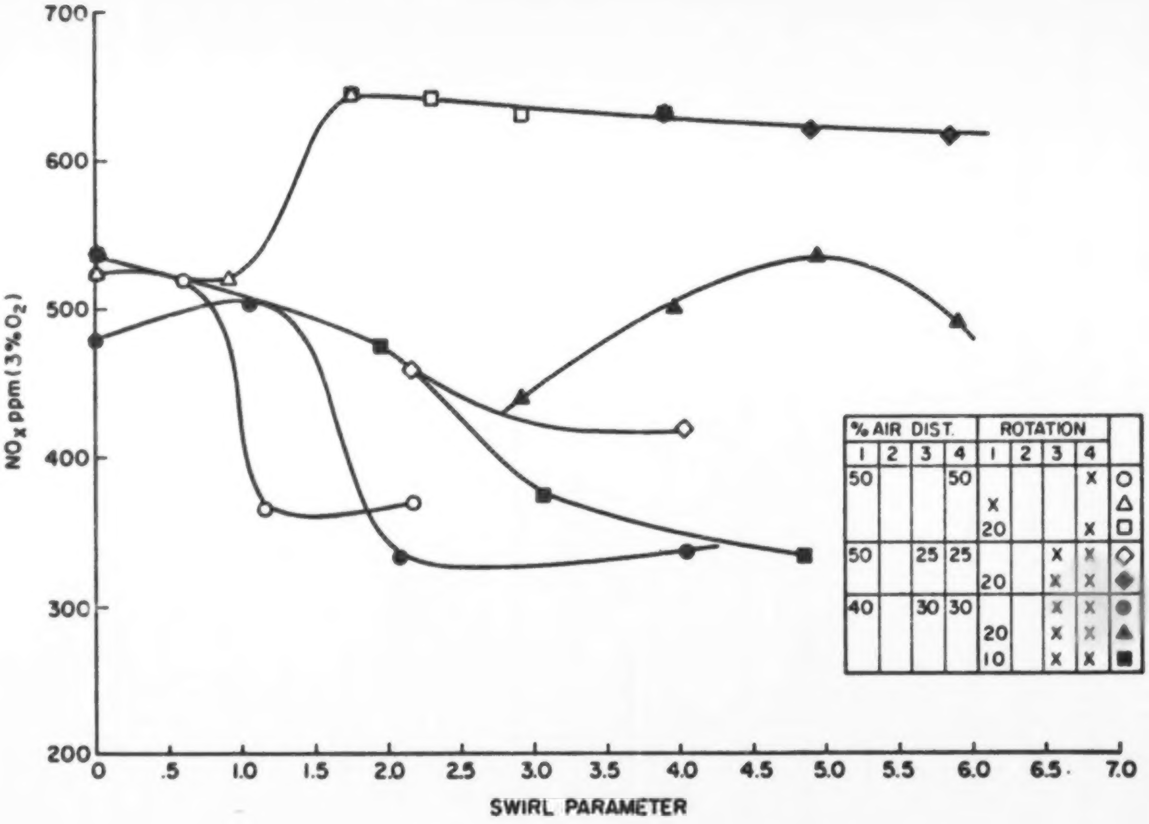


Figure 25. The Influence of Tangential Velocity Distribution on NO Emissions from Oil Flames (3 x 10^6 Btu/hr 80 gph Nozzle)

distribution between the channels, however, the results suggest that axial velocity distribution also influences emissions. In general, both nozzles exhibit similar trends. Emissions are maximized by free vortex type distributions and minimized by solid body type tangential velocity distributions.

4.0 CONCLUSIONS

Studies to optimize burner/combustor conditions to allow the control of nitric oxide formation in fuel oil flames are continuing. It has been shown to date that

1. Oil atomization parameters not only have a strong influence upon uncontrolled emissions, they also influence the effectiveness of staged combustion as a control technique.
2. Pollutant formation in confined oil flames is strongly dependent upon the distribution of axial and tangential velocity at the burner throat.
3. Field tests have demonstrated that 50 percent reductions in NO_x emission from firetube boilers are possible without incurring serious penalties due to emissions of other pollutants.
4. Thirty percent reduction in NO_x emissions from firetube boilers firing oil containing nitrogen can be obtained by flue gas recirculation. Reductions in watertube boilers will be strongly dependent upon combustion intensity.

REFERENCES

1. Heap, M. P., Lowes, T. M. and Martin, G. B, "The Optimization of Aerodynamic Design Variables to Control the Formation of Nitric Oxide in Fossil Fuel Flames." Fluid Mechanics of Combustion. p 75, The American Society of Mechanical Engineers (1974)

2. Pershing, D. W., Brown, J. W., Martin, G. B. and Berkau, E. C. "Influence of Design Variables on the Production of Thermal and Fuel NO_x from Residual Oil and Coal Combustion", paper presented at the Annual A.I.Ch.E., Meeting Philadelphia, 1973.

3. Pershing, D. W., Brown, J. W., and Berkau, E.E., "Relationship of Burner Design to the Control of NO_x Emissions Through Combustion Modification." Proceedings, Coal Combustion Seminar, EPA-650/2-73-021, NTIS PB224-210/AS, pp 87-140 (September 1973)

4. Muzio, L. J. and Wilson, R. P. Jr., "Experimental Combustor for Development of Package Boiler Emission Control Techniques," Phase I of III, EPA Report R2-73-292a, 1973.

5. Muzio, L. J., Wilson, R. P. Jr., and McComis, C., "Package Boiler Flame Modifications for Reducing Nitric Oxide Emissions," Phase II of III, EPA-R2-292b.

6. Heap, M. P., Tyson, T. J., McComis C., McMillan, R. E., Zoldak, F. D. and Sommerlad, R. E., "Control of Package Boiler Emissions by Staged Combustion and Flue Gas Recirculation," Phase III of III, Final Report EPA API Contract 68-02-0222.

7. Cato, G. A. and Robinson, J. M., "Field Testing Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers," Phase I, EPA Report 650/2-74-078a, October 1974.

8. Lee, K. B., Thring, M. W. and Beer, J. M., 1962 Combust. Flame, 6, 137-145.

9. Hemsath, K., "Mixing factors and Degree of Oxydation: Definitions and Formulae for Computation," I.F.R.F., Doc.nr. G 00/a/1^1, 1965

10. Siegmund, C. W. and Turner, D. W., "NO_x Emissions from Industrial Boilers: Potential Control Methods," ASME Paper 73 lPWR10, 1973.

10:45 a.m.
The Control of Pollutant Emissions from
Oil Fired Package Boilers
Dr. Michael P. Heap, Ultrasystems

Q: Could you tell us what the fuel nitrogen concentration was in the oil for the water tube test?

A: This is another sort of problem at the moment. Some of the analyses were done with a Coleman analyzer using the Dumas method, and there is some difficulty in reproducibility of results. In the past I have always had problems trying to analyze fuel for nitrogen using the Dumas method. Using the Kjeldahl method I always sort of got reproducible answers. I believe that the 0.1% figure is more or less correct.

Q: It seems that exhaust gas recirculation would have some significant thermal efficiency effects. I was wondering if you had extended your tests at all to consider this in relationship to the reductions or changes in pollutants.

A: This is being done at the moment but I don't have any information on it. It is part of the extension of the field test that is just being carried out this week.

Q: It may even pay to be a low polluter in such cases.

A: Certainly in the case of the fire tube boiler firing natural gas. One of the advantages is not only do you get the NO_x down to very low levels (about 15 ppm), but it also allows you to fire the boiler at less than 2% oxygen, which you couldn't do without the flue gas recirculation. So you could say it would improve the thermal efficiency that way.

Q: What kind of furnace heat release rates were you talking about in your package burner boiler tests? Volumetric heat release?

A: The laboratory one was designed that way so that it would be typical of a normal fire tube package boiler. The water tube combustion intensities--offhand I can't say, but we did have difficulty getting up to 100% load anyway. So the combustion intensities would be low. Most of the measurements were only done at less than 70% full load.

PILOT SCALE INVESTIGATION
OF CATALYTIC COMBUSTION CONCEPTS
FOR INDUSTRIAL AND RESIDENTIAL APPLICATIONS

by

J. P. Kesselring
C. B. Moyer
R. M. Kendall

Aerotherm/Acurex Corporation
Mountain View, California

J. A. Cusumano

Catalytica Associates, Inc.
Palo Alto, California

Preceding page blank

PILOT SCALE INVESTIGATION
OF CATALYTIC COMBUSTION CONCEPTS
FOR RESIDENTIAL AND INDUSTRIAL APPLICATIONS

J. P. Kesselring, C. B. Moyer, and R. M. Kendall
Aerotherm Division/Acurex Corporation
Mountain View, California

J. A. Cusumano
Catalytica Associates, Inc.
Palo Alto, California

The use of catalysts in place of conventional burners for promoting hydrocarbon oxidation reactions appears to have advantages in the control of emissions. The operating conditions of these catalytic combustors are limited by the catalyst bed temperature capability, and the temperature obtained through normal one-stage, low excess air operation that is necessary for efficiency reasons is outside the current temperature capability of catalyst systems. It is therefore necessary to consider other system techniques such as bed cooling, exhaust gas recirculation, or staged combustion to hold the bed temperature down. Based on a review of existing application and research programs involving catalytic combustion, a research and development program to establish design criteria for the application of catalytic combustion to low emission, high efficiency stationary combustion systems has been undertaken. This program consists of experimental catalyst and combustion concept screening, experimental and theoretical scale-up criteria, and development of prototype systems.

INTRODUCTION

More than 150 years ago, Sir Humphrey Davy discovered that platinum wires could promote combustion reactions in flammable mixtures. The resulting reactions appeared to take place on the surface of the wires, "without flame" and with the high radiative fluxes associated with the solid surface emittance rather than the low emittance of the combustion products (Reference 1). Subsequent study and investigation followed a number of paths reviewed by Spalding in Reference 2. Of this work, a substantial fraction which might be termed "fundamental studies of heterogeneous catalysis" has attempted to identify and quantify specific heterogeneous reactions and define the mechanisms by which the solid surface promotes or accelerates oxidation reactions. A second fraction, termed "computational", has dealt largely with mathematical theories and analyses attempting to describe the diffusion of reactants to the promoting surface, the diffusion of products away from it, and the combined heat and mass transfer. A final third fraction can be termed "reduction to practice", which includes attempts to construct and employ practical devices exploiting heterogeneous combustion. As is frequently the case in combustion, work in this area has proceeded with very little reference to achievements in fundamentals and computation. Experiments throughout the 1800's demonstrated that various materials promoted heterogeneous combustion reactions to various degrees, and that the number of materials with the ability to promote reactions increased as surface temperature increased. The earliest successful practial devices exploited heterogeneous combustion to provide more efficient lamps. The best example is the mantle lantern or Auer light, still sold in great numbers as a "camping lantern", in which combustion takes place on the ash residue of a fiber bag mantle surrounding the fuel/air orifice. This mantle ash contains oxides, including cerium oxide and thorium oxide, which in addition to constraining radiation emission to desirable lines in the visible spectrum, contribute to the catalytic activity of the mantle (Reference 3).

Concepts close to the original experiments of Davy have been used as passive ignition devices and as combustible detectors, particularly in the form of hydrogen leak detectors. Related applications along this line include catalytic fume abatement devices and automotive catalytic converters, both depending on precious metals to oxidize low concentrations of combustibles in gas streams.

After extensive practical experimentation, Bone publicized various high temperature applications of surface combustion, using for the most part conventional ceramic materials (Reference 4, 5). He built and tested surface combustion furnaces, boilers, and permeable panels. This line of investigation has not, however, proven very fruitful due to the complexity and expense of the required equipment and the limited industrial need for high radiative fluxes, although some commercial equipment of this type is available (Reference 6).

The range of commercial devices has recently led to some specialization of terminology in a field where formerly several terms were used interchangeably. The term "radiant burner" refers to burner types employing a refractory surface situated within or near the flame so as to provide for radiant heat transfer from the flame area. Heterogeneous combustion occurs in these devices to some degree, but generally does not dominate the process and homogeneous combustion constitutes most of the reaction mechanism. "Surface combustors" employ refractory in a similar manner but use special provisions of air/fuel distribution to maximize the amount of heterogeneous combustion occurring. "Catalytic combustors" employ special additives (usually precious metals) to enhance the heterogeneous activity of the surface.

There are several reasons for the recent upsurge of interest in catalytic combustion. Use of the diffusion flame for combustion appears to place a limit on the lower level of control that can be achieved economically for clean fuels (approximately 25 to 30 ppm of NO_x for small sources), and catalytic combustion appears to be able to reach lower levels of NO_x control (perhaps <10 ppm). In addition, catalytic combustion is soot-free, and the potential of high combustion efficiency for the overall system is present if the excess air can be limited in some way, such as two-stage combustion, flue gas recirculation, or cooling of the catalyst bed.

AVAILABLE CATALYST MATERIALS

The materials needed for a catalytic combustion system are those associated with the support, the washcoat, and the catalyst itself. The importance of each of these elements in the system is described below.

Support Materials

The catalytic support serves two important functions in a catalyst system:

- It increases surface area of the active metal or metal oxide by providing a matrix that stabilizes the formation of very small particles.
- It increases thermal stability of these very small particles, thus preventing agglomeration and sintering with consequent loss of active surface.

Most common support materials are $A\ell_2O_3$ and SiO_2. The application of these supports in catalytic combustion presents several significant problems that must be considered:

- The large space velocities used in a catalytic combustion unit will result in severe pressure drops if the catalyst beds are packed with conventional pellets like those used in the petroleum industry.

- The high reaction rates of complete combustion usually present severe pore diffusion limitations for the effective operation of the system.
- The high temperatures and heat fluxes place special constraints on the thermal properties of the system.

Over the last decade, a number of new materials and new preparative techniques have been developed to overcome these problems. These materials have emphasized the use of monolithic support structures and surface impregnated pellets.

Monolithic supports are composed of small parallel channels of a variety of shapes and diameters. These structures may be in the form of honeycombed ceramics extruded in one piece, oxidized aluminum alloys in rigid cellular configurations, or multilayered ceramic corrugations. The channels in honeycomb-like structures have tubular diameters of 1 to 3 mm. The overall diameter of the monolithic support may vary from 2 cm to 60 cm, and is limited, in the case of extrusion processes, by availability and operation of the metal die. Materials of fabrication are usually low surface area ceramics such as mullite ($3A\ell_2O_3 \cdot 2SiO_2$) or cordierite ($2MgO \cdot 5SiO_2 \cdot 2A\ell_2O_3$). The refractory monolith is produced with macropores (1μ - 10μ) and may be coated with thin layers of catalytic materials, 5-20 wt% coatings being common.

The two major advantages of monolith supports for catalytic operations are the high superficial or geometrical surface area and the low pressure drop during operation. Table I lists the currently available monolith materials, and Figure 1 shows typical extruded monolith structures.

TABLE I. AVAILABLE MONOLITH SUPPORTS

Manufacturer	Product	Description	Temperature Limit (°F)
American Lava Corporation	Thermacomb AℓSiMag 614	Dense 96% Alpha-alumina	2800
	Thermacomb AℓSiMag 776	Porous 96% alpha-alumina	2192
	Thermacomb AℓSiMag 795	Cordierite	2192
Corning Glass Works	Celcor 9475(EX-20)	Cordierite	2200
E. I. DuPont de Nemours & Company	TORVEX	Alumina	2732
		Mullite	2462
General Refractories Company	Versagrid	Cordierite	2550
		Mullite	3000
Norton Company	SPECTRAMIC honeycomb	Silicon carbide RX387	3000
		Silicon nitride RX384	2800
		Silicon oxynitride RX385	2800

In addition to the monoliths, highly porous pelleted materials can also be used as the catalyst support. Pellets come in a wide variety

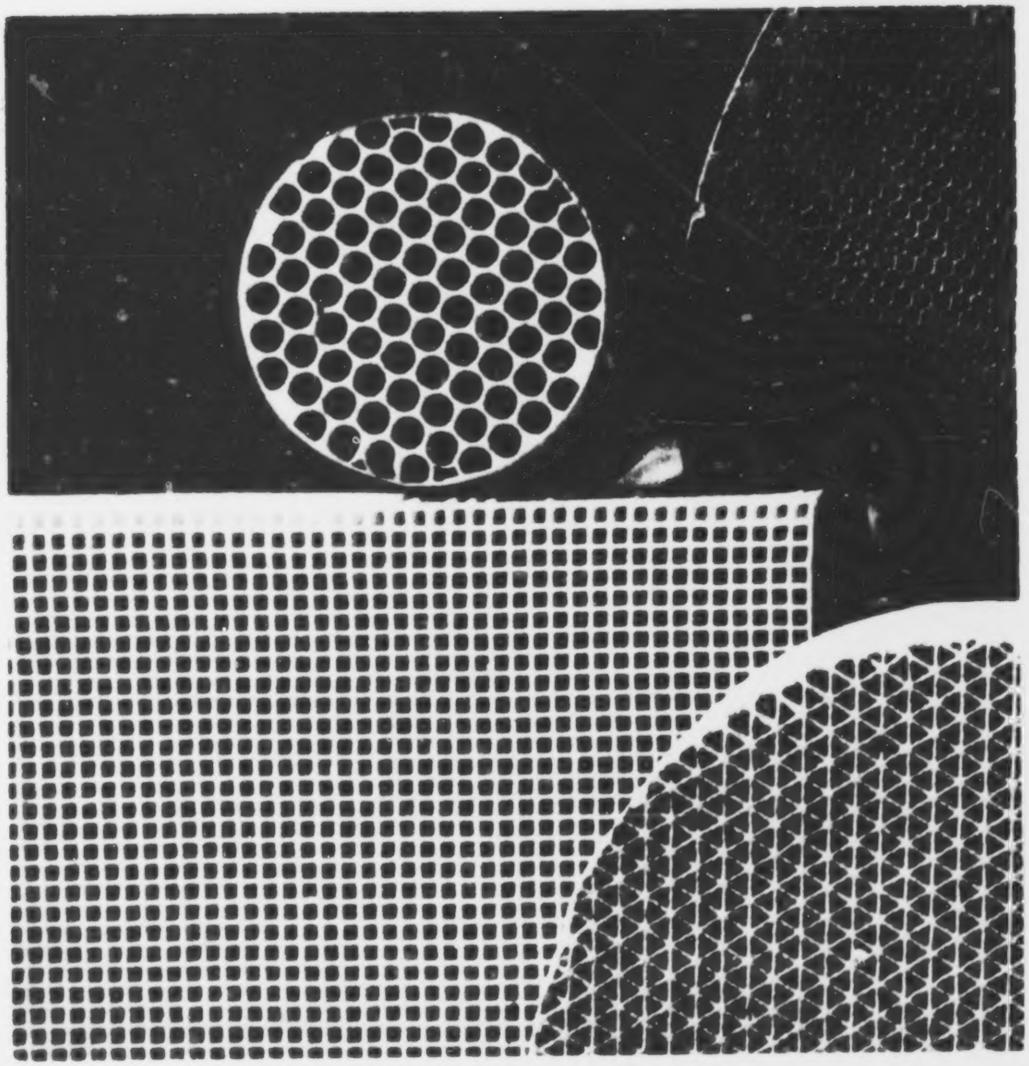


Figure 1. Typical extruded monolith structures (courtesy of General Refractories Company).

of materials, shapes, and sizes, but have the disadvantage of a higher pressure drop through the bed.

Wash Coat Materials

The low surface area of the monolith structure requires the application of a thin coat of oxide such as $A\ell_2O_3$. This wash coat, which strongly adheres to the ceramic or refractory support, provides a uniform high surface area while still insuring that the catalytic material which is subsequently impregnated on the wash coat is close to the main flow of reactants. The thickness of the wash coat is usually between 10×10^{-6} and 20×20^{-6} m (10-20 microns).

Many different materials can be used as wash coats. ZrO_2, for example, has been used in test runs for the catalytic combustion of hydrocarbons in automotive exhaust. Variation in the type of wash coat can have important consequences in the stability and life of the catalyst system.

Catalyst Coatings

Although the field of catalysis has progressed substantially over the past decade, its theoretical aspects are not yet at the degree of sophistication which would enable one, a priori, to choose or design an active oxidation catalyst with a given set of catalytic properties. However, a vast amount of data exists which permits the development of correlations useful for choosing promising candidates based on excellent catalytic activity and catalyst stability. Over the last decade there has been a rapid development of the art, science and technology necessary to synthesize, test and manufacture ultrastable oxidation catalysts for the abatement of automotive emissions. These catalysts operate under the most stringent conditions, and sometimes at temperatures close to 2000°F. The expertise developed in this area will be useful in the development of a stable catalytic combustion system.

Two broad classes of catalytic coating materials are available: metals and oxides. The metals of catalytic interest are listed in Table 2. Of these metals, the only ones which have a possibility of remaining in the metallic state in a high-temperature, oxidizing environment are the noble metals; the others readily form oxides. Of the noble metals, a large volume of data and correlations are available for platinum and palladium because of their use as automotive oxidation catalysts. They are among the most active catalysts for the oxidation of a number of fuels, including methane, methanol, and hydrogen.

TABLE 2. METALS OF INTEREST FOR CATALYTIC COMBUSTION

GROUP VIII*			GROUP IB*
Fe	Co	Ni	Cu
Ru	Rh	Pd	Ag
Os	Ir	Pt	Au

*Enclosed metals are considered noble.

The high activity of these metals is related to their ability to activate H_2, O_2, and carbon-hydrogen and oxygen-hydrogen bonds. Palladium and platinum are readily prepared in a highly dispersed form on a number of support materials. Because of the high activity of these metals per unit area of metal surface (specific activity) and the ability to attain high dispersions, only small amounts are necessary for catalytic combustion (0.1 - 0.5 wt%). Ruthenium metal is another possible candidate for catalytic combustion; however, under oxidizing conditions it forms a volatile oxide (RuO_4), which is rapidly removed from conventional catalyst supports. One approach to solve this problem has been to anchor Ru to a support by forming a relatively stable perovskite structure with certain oxides such as La_2O_3. Osmium is even more volatile and poisonous than ruthenium in an oxidizing environment. Also, as with iridium and rhodium, it is very costly, and available in limited supply. The use of the latter two metals, if at all, would be restricted to small quantities in multimetallic systems. Silver, while quite active at low temperatures for the activation of O_2, melts at low temperatures and therefore sinters to a significant degree at the high temperatures of catalytic combustion. However, it could find use as an additive in a multimetallic catalyst. Gold is very inactive for oxidation, and would therefore only be considered as a structural or electronic modifier for multimetallic catalysts.

Based on the above considerations, those metals which show the greatest promise for use in a single-active-element catalyst system are platinum, palladium, and ruthenium (stabilized). Highly active and stable catalyst systems can be produced through the use of multimetallic systems (such as palladium/platinum), as well.

The catalytic properties of metal oxides have been investigated by a number of researchers, including research in catalytic oxidation. As for metals, it has been found that the activity for hydrocarbon oxidation parallels the ability of the catalyst to catalyze the homomolecular exchange of oxygen. It has also been noted that the oxides of transition containing ions with partially-filled d-orbitals have the greatest activity. Based on these considerations, the most active simple oxides are Co_3O_4, MnO_2, NiO, CuO, Co_2O_3, Fe_2O_3, and V_2O_5. Multicomponent metal oxides of interest include stable spinel structures such as Co_3O_4/CuO, Cr_2O_3/CuO, and La_2O/Co_3O_4.

Temperature Capability of Catalyst/Support System

The choice of an optimum catalyst/support combination requires a consideration of the temperature capability of a given combination. The low temperature limit is dictated by the so-called "light-off" temperature. Solutions to this problem are not complex for most catalytic combustion systems, since noble metal catalysts exhibit good light-off characteristics for most fuels of interest. The major thermal limitation for catalytic combustion is the high temperature of operation. The phenomena which lead to catalyst deactivation at high temperatures are:

- Sintering of the catalytic species
- Changes in catalyst stoichiometry
- Sintering of the wash coat
- Thermal degradation of the ceramic support material
- Mechanical failures

Sintering of the catalytic species will lead to a concomitant loss in surface area and therefore a loss in catalyst activity per unit mass of catalyst. The temperature at which sintering occurs is a function of the catalytic material. In an oversimplified manner this sintering or crystallite growth is a function of the melting point for metals. A number of techniques have been developed to minimize or prevent sintering. For example, multimetallic systems can be prepared which are more stable than the constituent metals. A number of structural promoters are also known.

Stoichiometry changes for oxides can lead to a catalyst with dramatically different catalytic properties. Loss of lattice oxygen can cause an increase in the energy required to activate O_2 and thereby decrease combustion activity. One method for overcoming this problem is to dope the lattice with a material which causes a decrease in the energy necessary to activate oxygen and also stabilizes the stoichiometry of the lattice.

A third mechanism of thermal deactivation is wash coat sintering. At temperatures above 1650°F high surface area η- or γ-$A\ell_2O_3$ undergoes a phase change to α-$A\ell_2O_3$ with concomitant sintering. The change may be from a surface area of 300 m^2/g to about 5 m^2/g. This sintering results in pore closure and a "burying" of active catalytic sites in the $A\ell_2O_3$. To minimize this problem, it is possible to work with catalysts for which the catalytic phase has been deposited on a presintered $A\ell_2O_3$. Alternatively, other materials which are thermally more resistant may be investigated as wash coats. These might include ZrO_2 and ThO_2.

At very high temperatures, the ceramic support, be it spheres or monolithic honeycomb structures, begins to degrade. Typical monolith fail temperatures have been given in Table 1. Although catalytic combustion units are not expected to operate continuously at the temperatures listed, the possibility of local hot spots occurring due to uneven air/fuel mixing and local catalyst bed nonuniformities must be considered.

Thermal expansion and contraction may also occur at high temperatures. Both pellet and monolithic supports have thermal expansion coefficients different than their mounting hardware. Considerable catalyst mechanical attrition can occur if the catalyst becomes loose, thus causing a decrease in catalytic performance.

EXISTING APPLICATIONS OF CATALYTIC OXIDATION CONCEPTS

The existing applications of catalytic oxidation concepts in industry are largely in the low-temperature area at this time. The primary applications of catalytic combustion are in nitric acid plant tail gas cleanup, industrial odor control, small catalytic heaters, and automotive oxidation catalyst systems.

Nitric Acid Plant Tail Gas Cleanup

Nitric acid is produced commercially by reacting ammonia with air to produce nitrogen oxides, which are then absorbed in water to yield nitric acid. Large amounts of unabsorbed nitrogen oxides in the tail gas from the absorption tower pose a pollution problem, which has been solved in some cases by the catalytic processing of this tail gas over platinum-group metals to yield useful energy in the form of steam and/or power. The basic reactions for the catalytic treatment of nitric acid tail gas over platinum, palladium, or rhodium for methane reducing fuel are:

- $CH_4 + 4NO_2 \rightarrow 4NO + CO_2 + 2H_2O$ (decolorization)
- $CH_4 + O_2 \rightarrow CO_2 + 2H_2O$ (combustion)
- $CH_4 + 4NO \rightarrow CO_2 + 2H_2O + 2N_2$ (abatement)

The tail gas reactor outlet temperature is usually between 1250°F and 1380°F. Support materials for the catalyst have included nichrome wire, alumina pellets, and alumina honeycomb materials.

Industrial Odor Control

The elimination of organic fumes is desirable from both air pollution and fire safety points of view. The platinum metals have been used for several years as catalysts for the oxidation of carbon monoxide and a wide range of organic molecules in the presence of air or oxygen. Most odors are caused by the emission of low concentrations of organic molecules to the air, with these organic molecules always containing carbon and hydrogen and generally sulphur, nitrogen, and oxygen as well. Since most industrial odor problems are caused by organic compound concentrations well below the level required for spontaneous combustion in air, it is necessary to raise the contaminated air stream temperature to a level at which combustion can occur. The use of catalysts lowers the temperature needed to achieve odor removal, and also lowers the necessary residence time at the combustion temperature.

Low-Temperature Catalytic Heaters

Low-temperature catalytic heaters are characterized by the small portable radiant heaters that operate at temperatures below 800°F. Operating characteristics include heat release rates of approximately 75 Btu/in^2 and lifetimes of several thousand hours. Gaseous fuel is distributed in a uniform fashion to all parts of a catalytic pad, and combustion takes place on the surface of the fibers of the pad.

The Control Systems Laboratory of the EPA has conducted an extensive emissions testing program on a number of catalytic heaters, as reported in Reference 7. No correlation between emissions and specific heat release rates was found, and CO and UHC levels were generally quite high. However, NO levels were quite low for nearly all heaters tested. The high CO and UHC levels were attributed primarily to poor fuel-air mixing.

Automotive Exhaust Catalysts

Since platinum metal catalysts were selected for emission control on conventional automotive internal combustion engines for the 1975 model year, a great deal of development work went into these emission control systems. In general, NO_x emissions are controlled by a reduction mechanism, and CO and UHC emissions are removed by catalytic oxidation with secondary air added to the exhaust stream to ensure complete oxidation.

A reactor for catalytic exhaust emission control has three essential design features:

- A ceramic support on which the catalyst is deposited in a manner that prevents attrition
- Rapid warm-up of the catalyst unit, and hence rapid light-off
- Nearly complete conversion efficiency

The essential features of a satisfactory CO/UHC oxidation catalyst for automotive emission control are (Reference 8):

- A light-off temperature in the region of 250°C

- Conversion efficiencies in excess of 90 percent for both CO and UHC at space velocities up to 150,000/hr
- High temperature stability of the support and platinic crystallite system at temperatures to 950°C
- Poison resistance to compounds containing lead, phosphorous, and sulfur.

Platinum-palladium catalysts have been extensively tested in full-scale vehicle tests (Reference 9). The differences between platinum and palladium catalyst performances were quite small.

Reference 10 discusses possible substitute catalysts for platinum in automobile emission control. In this study, it was concluded that base metal catalysts generally are not as effective as platinum/palladium catalysts for automobile emission control, especially for hydrocarbon and carbon monoxide oxidation. For NO_x reduction, certain base metal catalysts initially are more active and selective than are noble metal catalysts; however, most suffer from rapid deactivation.

RESEARCH PROGRAM

Under EPA funding, an 18-month research program has been undertaken which emphasizes the understanding of the mechanisms of catalyst performance in the catalytic combustion process. The program includes catalyst screening tests on five different fuels, where such performance factors as light-off, conversion efficiency, extinction, poisoning, and temperature limits will be examined for both single- and multi-active component catalysts; the integration of promising catalyst systems into a catalytic combustion system for the purpose of evaluating the concepts of bed heat removal, exhaust gas recirculation, and two-stage combustion; and the development of an analytical model based on data obtained in the screening tests which will be capable of evaluating the performance of the catalyst system. All of these tasks will be accomplished at both small-scale (nominally 100,000 Btu/hr heat release rate) and large-scale (nominally 1,000,000 Btu/hr heat release rate) conditions. Each of these program elements will now be described in greater detail.

Screening Experiments

It is the intent of the screening experiments to provide an efficient means of evaluating catalyst bed performance, in order to permit the design of a variety of systems incorporating each catalyst bed. The evaluation of a catalyst for a combustion system differs in at least one major respect from more conventional catalyst applications (e.g., reforming, exhaust gas clean up, partial oxidation of organic compounds, etc.). This is the major heat release associated with the process. Because of the exponential relation between kinetic rates and temperature, these systems tend to "bootstrap" themselves rather than simply "cook" at an imposed temperature.

Any system concept will provide for heat removal in some way to limit maximum surface temperatures. To do this uniformly is not generally possible for packed bed or monolith systems. To achieve uniformity, varying amounts of inert dilution will be fed with the test streams into an effectively adiabatic reactor. The adiabatic flame temperature of this stream will approximate the maximum catalyst surface temperature within the system. The relative uniformity of temperature achieved during the screening experiments will greatly enhance the ability to obtain quantitative catalyst activity data from these tests.

The initial screening experiments, all to be run at atmospheric pressure, will be conducted in the existing Jet Propulsion Laboratory's catalytic combustion test facility. A photograph of this facility is shown in Figure 2. This facility has previously been used for research involving the catalytic partial oxidation of kerosene to produce a hydrogen-rich fuel for automotive applications. These screening experiments will initially focus on the performance variations of platinum catalysts on several substrates, with varying wash coats, in order to determine such things as the effect of wash coat deposition procedure, the effect of thermal deactivation of wash coat and catalyst, and the effect of chemical stabilization of the wash coat. Wash-coated supports will be supplied to Aerotherm by substrate manufacturers, and Aerotherm will prepare and apply the catalyst to the wash-coated support. The planned catalyst test matrix for the first 16 tests is shown in Table 3. All these tests will be run with natural gas as the fuel.

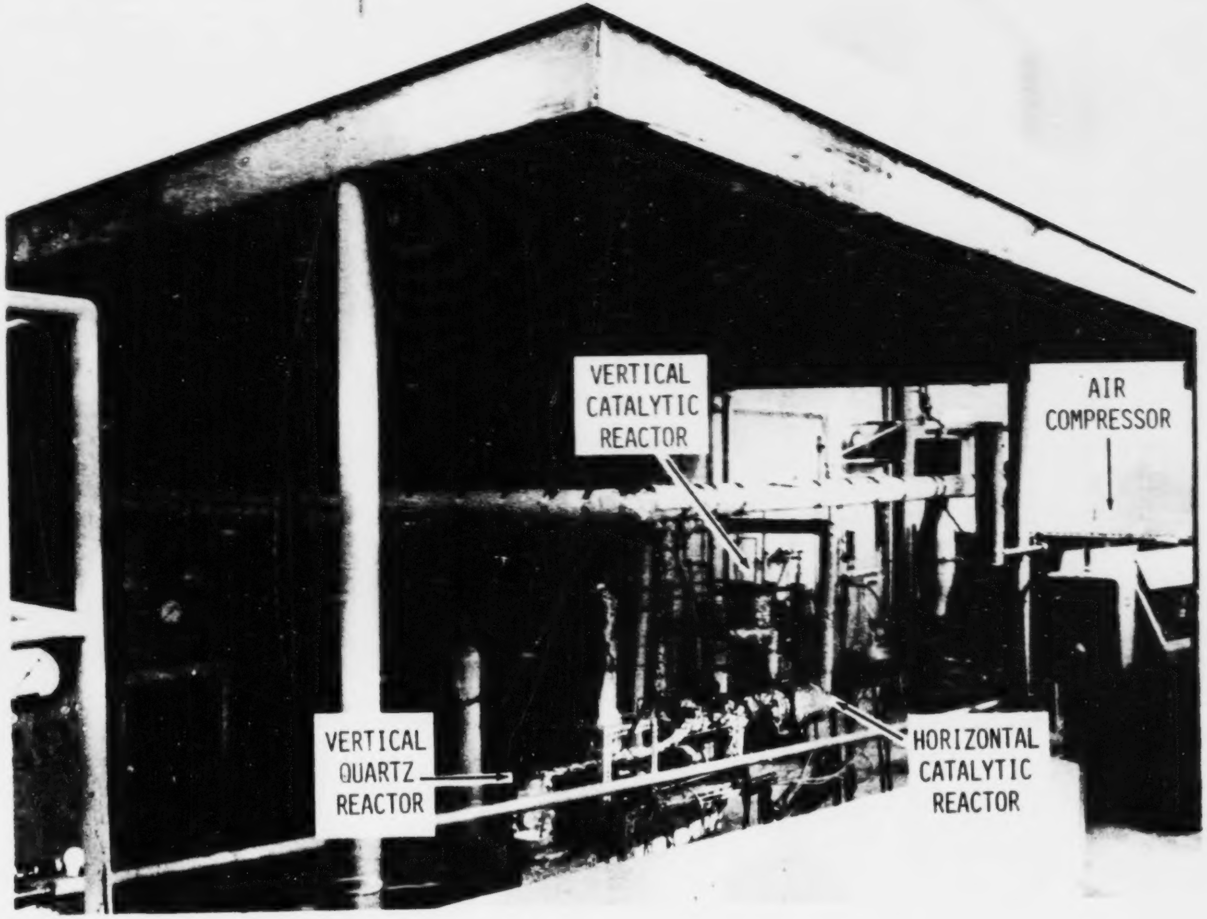

VERTICAL
CATALYTIC
REACTOR
AIR
COMPRESSOR
VERTICAL
QUARTZ
REACTOR
HORIZONTAL
CATALYTIC
REACTOR

Figure 2. JPL catalytic combustion test facility.

TABLE 3. PLANNED CATALYST MATRIX

FUEL = CH_4 JPL TESTS - 1 ATM PRESSURE

Test No.	Catalyst	Wash Coat	Substrate	Objective
1-5	Pt (OC)[1]	γ-$A\ell_2O_3$ (OC)	Mullite Cordierite	Line out JPL unit and optimize testing procedures
6	Pt(AERO)[2]	γ-$A\ell_2O_3$ (OC)	Mullite	Verify catalyst preparation capability
7-8	Pt (AERO)	γ-$A\ell_2O_3$ (OC)	Cordierite	Investigate effect of substrate
9	Pt (AERO)	γ-$A\ell_2O_3$ (MB)[3]	Mullite	Investigate effect of wash coat deposition procedure (cf. tests 1, 6)
10	Pt (AERO)	γ-$A\ell_2O_3$ (OC) (sintered)	Mullite	Effect of thermal deactivation (compare with test 1 as a standard)
11	Pt (AERO)	γ-$A\ell_2O_3$ (OC) (sintered)	Mullite	
12	Pt (AERO)	γ-$A\ell_2O_3$ (OC) (heat treated)	Mullite	Effect of thermal stabilization of wash coat
13	Pt (AERO)	γ-$A\ell_2O_3$ (OC) (Cs-doped)	Mullite	Effect of chemical stabilization of wash coat
14	Pt (AERO)	α-$A\ell_2O_3$	Mullite	Effect of ultrastable wash coat
15	Pt (AERO)	α-$A\ell_2O_3$	Spheres	Effect of catalyst bed geometry
16	Pt (AERO)	ZrO_2(Heat Treated)	Mullite	Effect of wash coat composition

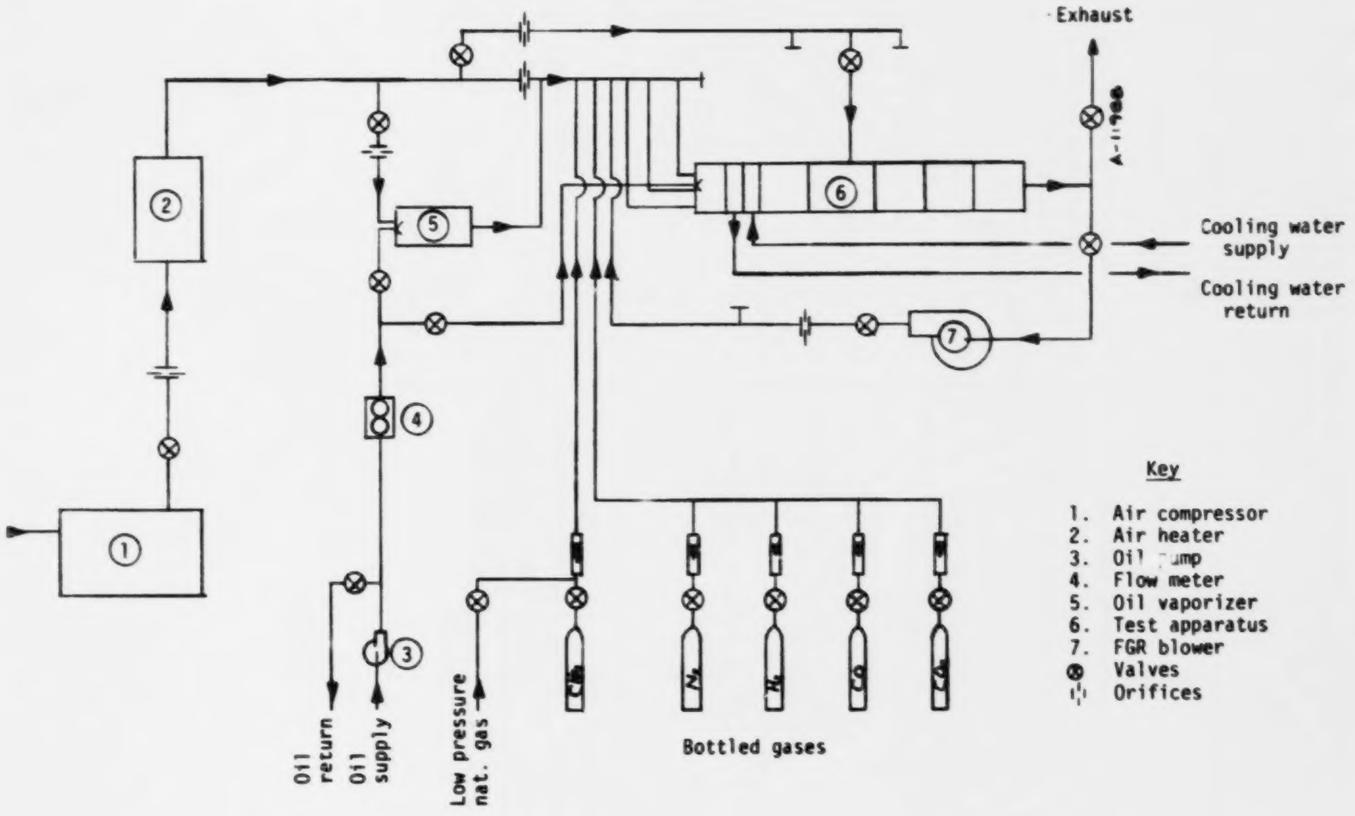
1. OC = Oxycatalyst 2. AERO = Aerotherm 3. MB = Matthey Bishop

Additional screening tests will be conducted with four other fuels: #2 distillate oil, methanol, hydrogen, and low Btu gas. The remainder of the screening experiments at JPL will focus on establishing light-off temperature, extinction limits, and poisoning effects for a variety of catalyst. Multi-active-component catalyst systems will be developed based on the most promising single-active-component catalysts tested and will be tested with the five different fuels mentioned previously. The evaluation criterion for catalyst performance will be the effect of a test variable on pollutant emissions, e.g., CO, UHC, and NO_x.

While the initial screening experiments are being conducted at JPL, Aerotherm will be constructing a catalytic combustion test facility for the remainder of the experimental work on this contract. A schematic diagram of this facility is shown in Figure 3. This facility will be capable of testing at pressures up to 10 atmospheres, and will be capable of doing both small- and large-scale testing. It will initially be used in the conduct of the high-pressure screening tests and the catalyst life tests. An overview of all testing to be conducted during this study is given in Table 4.

System Concept Evaluation Experiments

The focus of the system concept evaluation will be on effectiveness of various heat extraction techniques and their effect on catalyst performance (kinetic and thermal stability). All of these experiments will be conducted in the Aerotherm test facility in the versatile



Exhaust
A-11988
Cooling water supply
Cooling water return
Oil return
Oil supply
Low pressure nat. gas
Bottled gases
CH_4
N_2
H_2
CO
CO_2
①
②
③
④
⑤
⑥
⑦
Key
1. Air compressor
2. Air heater
3. Oil pump
4. Flow meter
5. Oil vaporizer
6. Test apparatus
7. FGR blower
⊗ Valves
╬ Orifices

Figure 3. Schematic catalytic combustion versatile test facility.

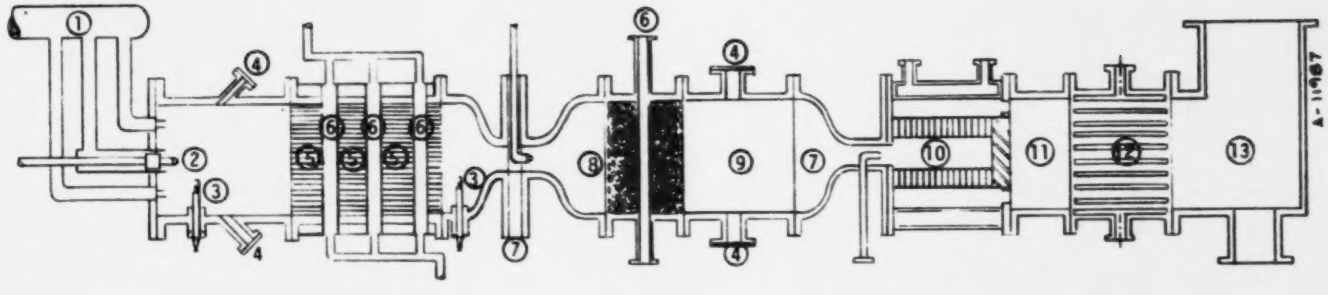
TABLE 4. OVERVIEW OF CATALYST SCREENING AND SYSTEM EVALUATION TESTS

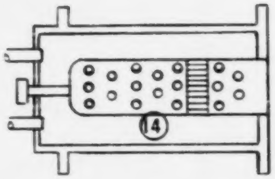
Element	Test Series	Primary Purpose	Approximate Number of Tests
Small-scale catalyst systems	Single-catalyst screening (1A)	Preliminary evaluation of single-catalyst performance	70
	Multi-component catalyst screening (1B)	Preliminary evaluation of multiple-component catalyst performance	13
	Selected catalyst system evaluation (1C)	Perform extensive evaluation of selected catalyst systems	28
Small-scale system studies	Concept evaluation (1D)	Integrate promising catalyst systems into a practical combustion system	34
Large-scale catalyst systems	Large-scale catalyst screening (2A)	Extensive evaluation of selected catalyst performance	35
Large-scale system studies	Concept development (2B)	Development of optimum combustion system configurations	34

catalytic combustion test apparatus shown in Figure 4. In this figure many possible concepts are shown connected in series, but only for illustrative purposes. In actuality, only a few of the segments would be assembled to test a particular concept. The versatile test apparatus is capable of testing flue gas recirculation, two-stage combustion, and bed heat removal concepts. Table 4 gives an overview of the system concept tests to be conducted.

Data Analysis

In order to establish the data reduction procedures associated with obtaining catalyst activity, Figure 5 must be considered. In preparing this idealized representation of wall events it is assumed that heat and mass transfer coefficients are equal, that diffusion coefficients are also equal, and that the system is adiabatic, so that enthalpy is constant. It should be emphasized that these assumptions are for the idealized representation only, and do not necessarily represent what will actually be used in the data analysis. The independent variable selected, K_{r_w}, represents the wall concentration of the lean reactant. The dependent variables are $\dot{m}_{TRAN}$, $\dot{m}_{REAC}$, and T_{WALL}. $\dot{m}_{TRAN}$ is the mass flux of reactant to the wall, and $\dot{m}_{REAC}$ is the mass flux of reactant consumed by the catalyst, while T_{WALL} is the wall temperature and is proportional to the fraction of reactants consumed at the wall. This proportionality is assumed to be linear in the sketch. Thus, when all reactants are consumed away from the wall the adiabatic flame temperature is reached. A steady-state solution is reached when the mass flux of reactants to the

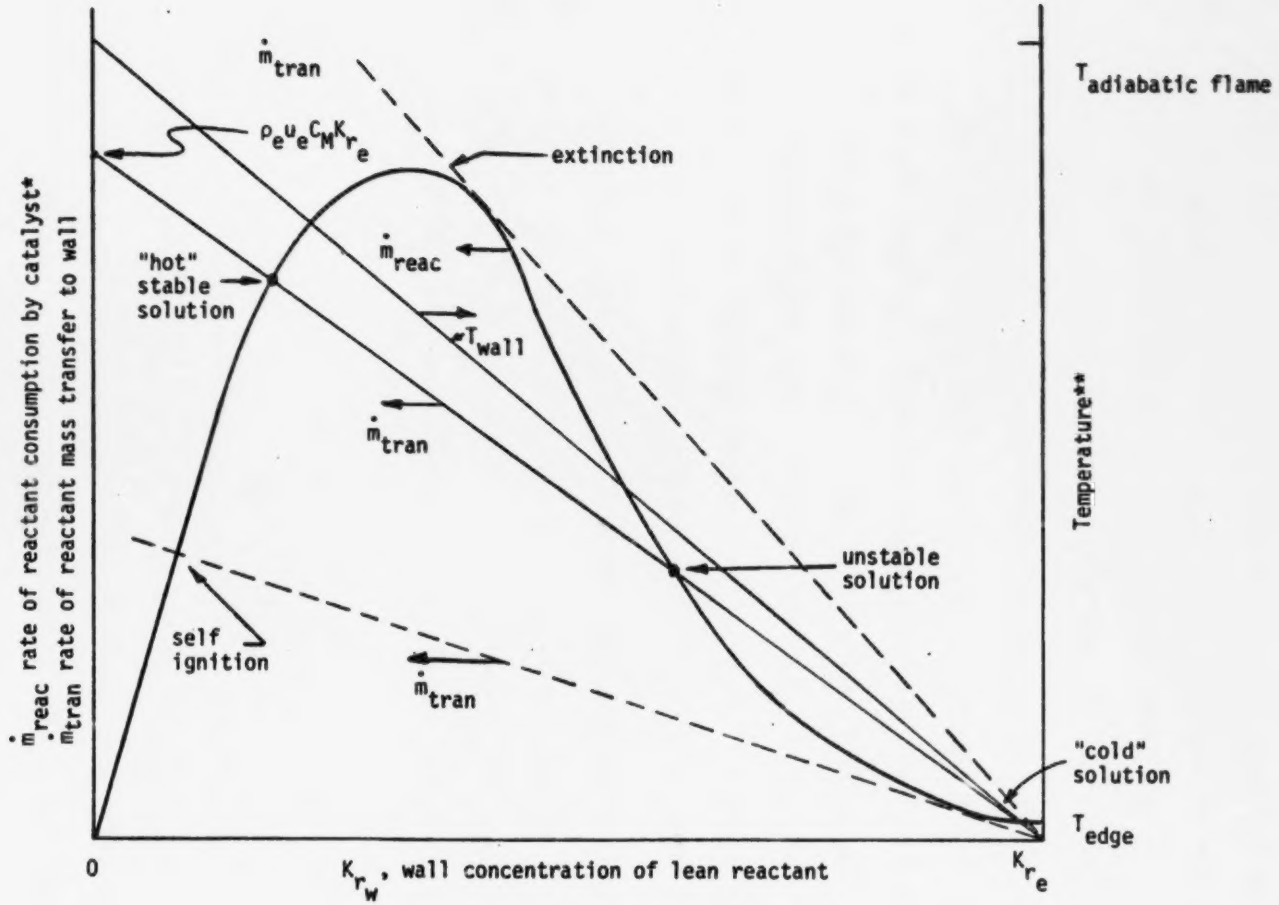




LEGEND

1. Fuel/Air Manifold
2. Conventional Burner
3. Ignitor
4. Viewport/U.V. Flame Sensor Port/
   Sampling Port
5. Monolith Catalysts & Holder
6. Cooling Segments
7. Staging Section
8. Packed Bed Catalyst Holder
9. Mixing/Retention Section
10. Radial Catalyst Test Section
11. Spacer
12. Final Heat Exchanger
13. Turning Section/FGR Port
14. Gas Turbine Combustor Section

Figure 4. Versatile catalytic combustion test apparatus.



$^{*}\dot{m}_{reac}$ presumed proportional to $K_{r_w} e^{-\Delta E/RT}$

$^{**}T_{wall}$ presumed proportional tc extent of reaction as related to conversion of reactants at wall

Figure 5. Simplified wall events in a catalytic oxidation process.

wall is equal to the mass-flux of reactants consumed at the wall, and is represented by the intersection of an $\dot{m}_{TRAN}$ curve with the $\dot{m}_{REAC}$ curve shown. Both "cold" and "hot" stable solutions can occur, but the "hot" stable solution is the one of interest.

Two items of interest in Figure 5 are events concerning self-ignition and extinction. Self-ignition of the bed can occur at very low space velocities if effectively adiabatic conditions occur. At high values of space velocity the value of the mass transfer coefficient $\rho_e u_e C_M$ will also increase, and eventually extinction will occur. The extinction space velocity values for a few adiabatic flame temperatures can provide a characterization of a given catalyst bed/fuel combination.

In addition to the preceding "thermal" analysis, exit composition measurements will further assist in the formulation of the surface kinetic reaction processes. In addition, the effectiveness of the catalyst to yield equilibrium NO_x compositions at its surface will also be evaluated.

SUMMARY

The use of catalysts in place of conventional burners for promoting hydrocarbon reactions appears to have advantages in the control of emissions. A research program has been undertaken that addresses the basic lack of knowledge concerning catalyst characteristics, wash coat, support, and bed depth required for an oxidation reaction to go to completion. In addition, the program will study system techniques such as bed cooling, exhaust gas recirculation, and staged combustion to hold the bed temperature down. The results of this study will be directly applicable to the design of compact catalytic combustion systems for residential and industrial applications.

REFERENCES

1. Davy, H., "Some New Experiments and Observations on the Combustion of Gaseous Mixtures," J. Davy, ed., *The Collected Works of Sir Humphrey Davy, Vol. VI*, Miscellaneous Papers and Researches, Part I, On the Safety Lamp for Preventing Explosions in Mines, Houses Lighted by Gas, Spirit Warehouses, or Magazines in Ships, etc., With Some Researches on Flame, Section II, Papers Published in the Philosophical Transactions and in the Journal of Science and the Arts, on the Fire Damp, the Safety Lamp, and on Flame, Smith, Elder, and Co., Cornhill, London, 1840, pp. 81-88.

2. Spalding, D. B., "Heat Transfer from Chemically Reacting Gases," Ibele, W., ed., *Modern Developments in Heat Transfer*, Academic Press, N.Y., 1963, pp. 19-64.

3. Lütken, A. and Holst, H., *Opfindelsernes Bog*, Vol. IV, Nordisk Forlag, København, 1914, pp. 131-139.

4. Bone, W. A., "Surface Combustion and Its Industrial Applications," *Engineering*, Vol. 91, April 14, 1911, pp. 487-489.

5. Bone, W. A., "Surface Combustion," *Engineering*, Vol. 93, May 10, 1912, pp. 632-634.

6. Walker, W. H., Lewis, W. K., McAdams, W. H., and Gilliland, E. R., *Principles of Chemical Engineering*, 3rd Edition, McGraw-Hill Book Company, Inc., New York, 1937, pp. 202-204.

7. Thompson, R. E., Pershing, D. W., and Berkau, E. E., "Catalytic Combustion — A Pollution-Free Means of Energy Conversion." Environmental Protection Technology Series EPA-650/2-73-018, Aug. 1973.

8. Acres, G. J. K., Bird, A. J., and Davidson, P. J., "Recent Developments in Platinum Metal Catalyst Systems," The Chemical Engineer, March 1974.

9. Barnes, G. J. and Klimisch, R. L., "Initial Oxidation Activity of Noble Metal Automotive Exhaust Catalysts," SAE Paper 730570, presented at the Automobile Engineering Meeting, Detroit, Michigan, May 14-18, 1973.

10. National Materials Advisory Board, "A Semi-Delphi Exercise on Substitute Catalysts for Platinum in Automobile Emission Control Devices and Petroleum Refining," NMAB-314, March 1974.

TABLE OF CONVERSION FACTORS FOR METRIC UNITS

English Units		Metric Units
atmosphere	=	1.0133×10^5 newtons/meter^2
Btu	=	2.52×10^2 (g) cal
Btu/hour	=	2.52×10^2 (g) cal/hour
degrees Fahrenheit	=	$(t_F - 32)/1.8$ degrees Celcius
foot	=	3.048×10^{-1} meters
inch	=	2.540×10^{-2} meters

11:40 a.m.

Pilot Scale Investigation of Catalytic Combustion Concepts for Industrial and Residential Applications

Dr. John P. Kesselring, Aerotherm Acurex Corporation

Q: Will you be considering the possibility of using a catalyst monolithic screen in a location between a furnace and a heat exchanger as a burnout medium for soot that is passing through?

A: We will not be considering that in this program. In fact, the avoidance of sooting conditions in catalytic combustion appears important, since active sites can be buried by soot deposition inside the monolith.

THE OPTIMIZATION OF BURNER DESIGN PARAMETERS TO CONTROL NO_x FORMATION IN PULVERIZED COAL AND HEAVY OIL FLAMES

M. P. Heap, T. J. Tyson and G. P. Carver
Ultrasystems, Inc.
G. B. Martin
Environmental Protection Agency
and
T. M. Lowes
Associated Portland Cement Manufacturers

ACKNOWLEDGEMENTS

The work reported in this paper was carried out under EPA Contracts 68-02-0202 (International Flame Research Foundation) and 68-02-1488 (Ultrasystems, Inc.). Two of the authors (M.P. Heap and T. M. Lowes) wich to express their appreciation to all their former colleagues at the IFRF Research Station. Dr. E. E. Berkau and Mr. D. W. Pershing made significant contributions to this work by virtue of many stimulating discussions.

1.0 INTRODUCTION

In recent years considerable effort has been expended in an attempt to reduce the emission of nitrogen oxides from stationary combustion sources. Several parallel paths have been followed in an attempt to achieve this objective, including the modification of operational procedures and system redesign. This paper describes a series of small scale investigations which were carried out to identify burner parameters which control nitric oxide formation in pulverized coal and heavy fuel oil flames. The amount of nitric oxide produced in turbulent diffusion flames appears to be strongly dependent upon the rate of fuel/air mixing. Two burner design options have been identified which control mixing and, therefore, influence nitric oxide formation. These options are:

- the method of fuel injection, and
- the method of combustion air delivery.

Both options also affect flame length, flame volume and heat absorption at the boundary of the combustion chamber. The paramount objective of the investigations discussed in this paper is the satisfaction of combustor requirements as well as the minimization of pollutant emissions. Plans will also be discussed to investigate the influence of scale and multiple burner systems on low emission, high efficiency combustion systems suitable for both industrial and utility boilers.

2.0 NITRIC OXIDE FORMATION IN PULVERIZED COAL AND HEAVY OIL FLAMES

Nitrogen oxides are formed from two sources of nitrogen during the combustion of fossil fuels, molecular nitrogen, and nitrogen compounds which occur naturally in both liquid and solid fuels. The reactions controlling the rate of oxidation of molecular nitrogen, producing thermal NO, are strongly temperature dependent and proceed at significant rates only above 1600°C. It was originally thought that the reaction between nitrogen molecules and oxygen atoms was mainly responsible for NO production in flames. However, it is now believed that reaction of hydrocarbon radicals with molecular nitrogen in a flame zone provides an additional path for thermal NO formation. Nitrogeneous material in fossilized animals and vegetation provided the source for nitrogen compounds which are present in coal and oil. During the combustion of these fuels some of this nitrogen is oxidized giving fuel NO. The amount of fuel NO formed in simple premixed flames is not strongly dependent upon temperature, but it is most sensitive to oxygen availability.

The processes involved in heat release and nitric oxide formation in pulverized coal and heavy oil flames are extremely complex. The fuel and air are supplied separately to the combustion chamber through a device which ensures that they are mixed and that the fuel is in a condition to ignite and burn completely. In order to discuss those features of practical flames which influence NO formation the total process will be considered in three simple stages.

Fuel Preparation. Liquid fuels are atomized, mixing takes place between the fuel, the combustion air and recirculated hot combustion products. Both liquid and solid fuels evolve gaseous components which will ignite under suitable conditions.

Heat Release. The nature of the fuels and the turbulent mixing process allow heat release to take place in several modes. The volatile fuel fractions can burn: 1) in homogeneous premixed zones, or 2) in diffusion flames around single droplets or clouds of droplets. Soot formed from the volatile fuel fractions must be oxidized as must the char which remains after the devolatilization of the coal particles.

Heat Transfer. The products of combustion leave the heat release zone and mix with the bulk gases and lose heat before leaving the combustion chamber.

In cold wall combustion chambers nitric oxide production can be considered to occur only during the heat release stage. Extensive reviews of the kinetic mechanisms associated with thermal NO formation in hydrocarbon flames are available;(1,2) but for the purposes of this discussion it is convenient to refer to the two dominant mechanisms as Zeldovich, i.e.,

$$N_2 + O \longrightarrow NO + N$$

or Fenimore,(3) i.e.,

$$N_2 + R \longrightarrow RN + N$$

where R is some hydrocarbon fragment such as CH, and oxidation of the nitrogen fragments produces NO. The Zeldovich path will be dominant in fuel lean zones, and the amount of thermal NO produced will depend upon:

- the stoichiometry of the reaction zone;
- the amount of diluent combustion products in the reaction zone;

- the temperature of those diluents; and
- the rate at which the freshly formed combustion products mix with bulk gases and thus their rate of temperature decay.

The Fenimore path will be dominant in fuel rich zones, and the amount of NO produced will probably depend upon the carbon/hydrogen ratio of the fuel fragments.

Sternling and Wendt(2) discussed the fate of chemically bound nitrogen during the combustion of solid and liquid fuels. Lacking definitive experimental results these workers assembled fragmentary data and concluded that 80 percent of the nitrogen in coal would appear in the coal char and that a smaller, but still major, portion in the solid formed after devolatilization of oil droplets. Subsequent oxidation of the char would then produce the major portion of the fuel NO. Heap et al,(4,5) postulated that fuel NO accounted for the major portion of the emission from coal flames and that the fuel NO was mainly formed from "volatile" fuel nitrogen compounds. Pershing et al,(6) burned coal with both air and oxygen/argon mixtures and showed that approximately 80 percent of the total emission could be attributed to fuel NO. The possible fate of chemically bound nitrogen in an oil droplet or coal particle is traced in Figure 1.

A simple working hypothesis of fuel NO formation can be constructed based upon available information from studies involving doped fuels and the addition of nitrogen compounds to laboratory premixed

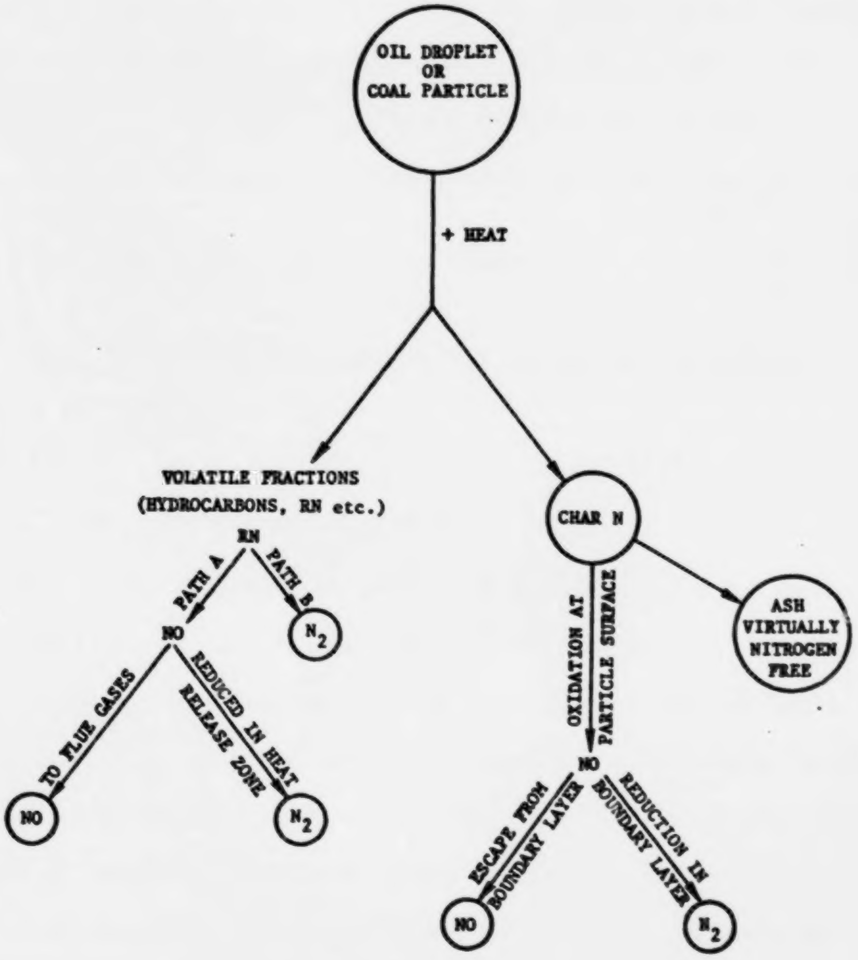

OIL DROPLET
OR
COAL PARTICLE
+ HEAT
VOLATILE FRACTIONS
(HYDROCARBONS, RN etc.)
RN
PATH A
PATH B
NO
N2
TO FLUE GASES
REDUCED IN HEAT
RELEASE ZONE
NO
N2
CHAR N
OXIDATION AT
PARTICLE SURFACE
ASH
VIRTUALLY
NITROGEN
FREE
NO
ESCAPE FROM
BOUNDARY LAYER
REDUCTION IN
BOUNDARY LAYER
NO
N2

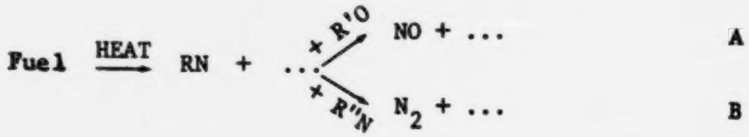
Figure 1. The Possible Fate of Fuel Nitrogen Contained in Coal Particles or Oil Droplets During Combustion

and gaseous diffusion flames. The primary fuel nitrogen compounds are broken down yielding secondary intermediate compounds RN which are subject to two competitive reaction paths:

A — reaction with an oxygen containing species producing NO, or

B — reaction with a nitrogen containing species producing N_2.

Thus the formation of fuel NO can be considered simply as



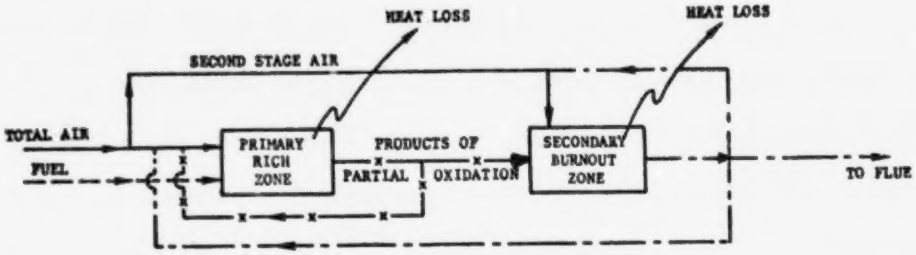
The production of nitrogen (path B) will be favored under fuel rich conditions and the conversion of fuel nitrogen to fuel NO in flames can be limited by ensuring that the majority of fuel nitrogen compounds react under oxygen deficient conditions.

Once formed, nitric oxide can be reduced in heat release zones, a process which could allow the net production of NO in flames to be reduced. An experimental study by Wendt, Sternling, and Matovich(7) demonstrated that "reburning" was effective and that up to 50 percent reduction in flue gas NO level was obtained. Engleman et al,(8) added NO to a well-stirred reactor burning methane/air mixture and found that almost all the NO was retained in lean mixtures, but that the 65 percent of the input NO was reduced when it was added to reactants containing only 65 percent of the stoichiometric air requirements.

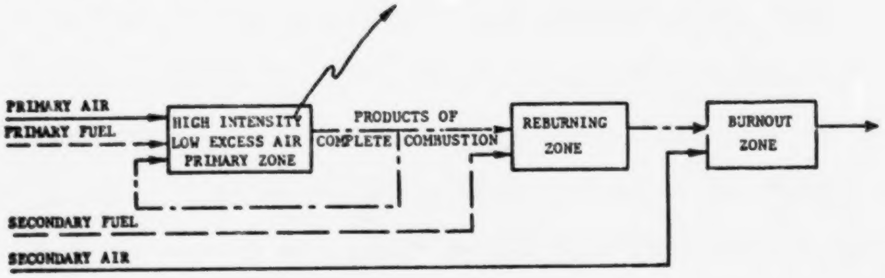
Sarofim et al,(9) demonstrated that a "diffusion flame environment" facilitated NO destruction. Myerson(10) has shown that NO contained in simulated combustion products can be reduced by isobutane when flowed through a heated ceramic tube at temperatures in excess of 1000°C. More recent information on NO reduction by hydrogen has been presented by Flower, Hanson and Kruger(11). Thus, the possibility exists that NO could be produced in the early stages of heat release and reduced before leaving the heat release zone.

None of the previous discussion has alluded to the possibility of NO_2 production in flames. Nitrogen dioxide has been observed in both flat flames and turbulent diffusion flames. In flat flames the NO_2 is produced in the visible flame region and, in most cases, is rapidly converted to NO downstream of the visible zone. High NO_2 concentrations have been observed in regions of high shear or on the periphery of the base of natural gas air flames.(12,13) The effects of NO_2 formation in coal and heavy oil flames are unknown. In fuel oil or pulverized coal flames it is unlikely that the rapid formation and destruction of NO_2 within the heat release zone would influence the net production of NO unless this process competes with those reactions leading to the formation of N_2 from NO. Consequently, NO would be converted to NO_2 only to be reformed at a later stage, rather than being reduced to N_2.

Two generalized schemes are presented in Figure 2 to illustrate possible approaches to the control of the net production of NO in


HEAT LOSS
HEAT LOSS
SECOND STAGE AIR
TOTAL AIR
FUEL
PRIMARY RICH ZONE
PRODUCTS OF PARTIAL OXIDATION
SECONDARY BURNOUT ZONE
TO FLUE

STAGED HEAT RELEASE


PRIMARY AIR
PRIMARY FUEL
HIGH INTENSITY LOW EXCESS AIR PRIMARY ZONE
PRODUCTS OF COMPLETE COMBUSTION
REBURNING ZONE
BURNOUT ZONE
SECONDARY FUEL
SECONDARY AIR

REBURNING

Figure 2. Generalized Schemes for the Reduction of NO Emission from Turbulent Diffusion in Flames

turbulent diffusion flames. The more familiar approach is through staged heat release by reducing the rate at which air is mixed with the fuel. Thus a rich primary zone is produced which creates conditions favorable for path B. The crucial practical implications of this system are that the second stage air must be added in such a way as to ensure complete combustion within the constraints imposed by practical systems; i.e., the need to produce steam and all that this implies in terms of both thermal and operating efficiency. Although in Figure 2 the primary and secondary zones are shown as being physically separated, this must not necessarily be the case — some compromise being necessary to accommodate the heat release zone in the available physical space.

The alternate scheme for the NO_x control during combustion of nitrogen containing fossil fuels is based upon the concept of reburning. High intensity rapid mixing conditions favor both NO formation and efficient combustion. In the primary region the major portion of the fuel is burnt without regard for NO control. Secondary fuel is added to the products of combustion and the nitric oxide is reduced in the fuel rich mixtures. Subsequent addition of air completes combustion. This scheme would require rapid mixing of the secondary fuel with the primary products which should contain the minimum amount of excess air, probably requiring that the secondary fuel be gaseous.

This paper is concerned with investigations to determine the optimum mixing pattern to control nitric oxide formation by the former scheme, which aims to prevent excessive formation of nitric oxide in the primary zone and promote burnout of the partially oxidized fuel in the secondary zone.

3.0 SUBSCALE EXPERIMENTS TO ESTABLISH OPTIMUM CONDITIONS FOR MINIMUM POLLUTANT EMISSIONS

EPA Contract 68-02-0202 carried out by the Staff of the International Flame Research Foundation, IJmuiden, Holland, was concerned with defining those burner parameters which control the rate of NO formation in turbulent pulverized coal and heavy fuel oil flames. The results of these investigations will be described to illustrate various approaches which can be used to provide the conditions illustrated in Figure 2 as staged heat release. Two methods have been identified which allow the control of nitrogen oxide formation while maintaining satisfactory combustion conditions. These are:

- division of the total combustion air supply into separate streams, thus delaying mixing the total air supply with all the fuel,
- optimization of the method of fuel injection.

The subscale experiments were carried out in a refractory tunnel furnace of 2 meters cross section and 6 meters long; complete details of the experimental system have been given elsewhere.(13) Figure 3 presents a schematic showing the arrangement of the versatile test burner used in the investigations. This burner utilized the moving block swirl generator designed by Leuckel(4) and readily allowed the influence of several parameters on pollutant emissions to be investi-

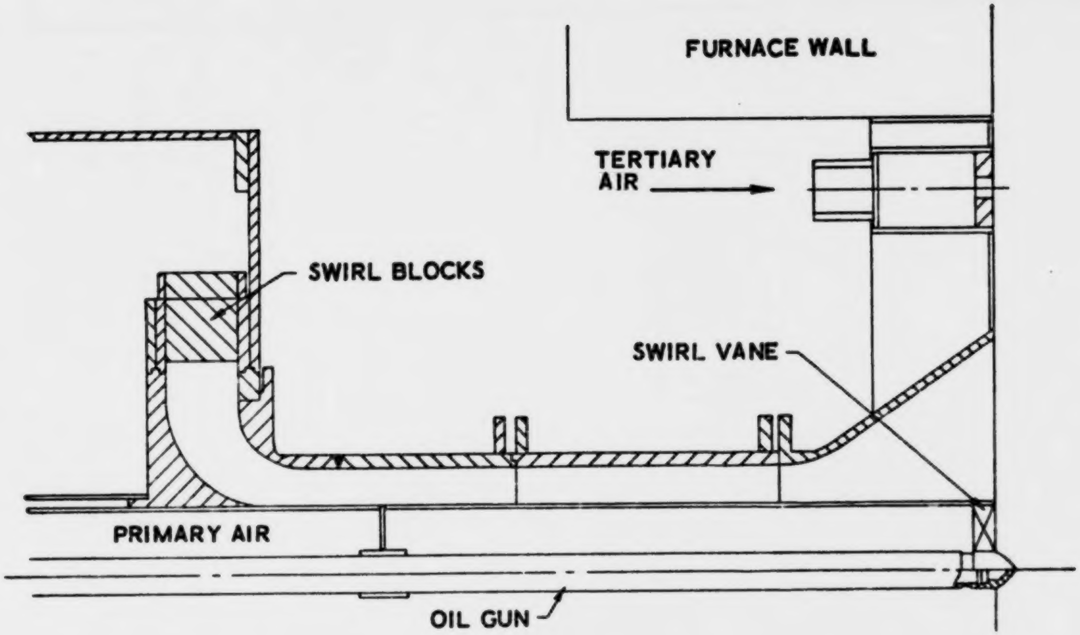

FURNACE WALL
TERTIARY AIR
SWIRL BLOCKS
SWIRL VANE
PRIMARY AIR
OIL GUN

Figure 3. Schematic of Versatile Test Burner Assembly for Oil Firing Showing Diversion of Total Air into Three Streams and the Primary Fixed Vane Swirler

gated. The most significant being 1) the method of fuel injection, 2) division of the total air supply between primary, secondary and tertiary air streams, 3) the secondary swirl imparted by the moving blocks, 4) the primary swirl imparted by fixed vanes, 5) the angle of the burner divergent, 6) the number of injection points for the tertiary air supply, and 7) the position of the fuel injector relative to the burner exit.

3.1 Optimization of the Method of Fuel Injection

Parametric studies very quickly indicated that the method of fuel injection had a profound effect upon nitric oxide emission from pulverized coal flames. Measured emissions ranged from 800 to 200 ppm for a 1.1 percent nitrogen coal with 300°C preheat and 5 percent excess air. Maximum emissions were achieved when the fuel was injected radially into the air stream. Heap et al,(5,13,15) postulated that this method of fuel injection provided the most oxygen-rich conditions for the combustion of the volatile coal fractions. Those injection conditions which tended to minimize the rate of mixing between the fuel and the total combustion air gave minimum emissions of nitric oxide, and were provided by a high velocity axial fuel injector utilizing the minimum amount of primary air. Figure 4 gives an impression of the range of emissions obtained for a given primary air percentage, excess air level and burner geometry. Although pulverized coal flames could be produced with low NO emission, the length of these low NO flames is unacceptable for use in existing boiler configurations. Practical requirements in utility boilers dictate stable, high intensity

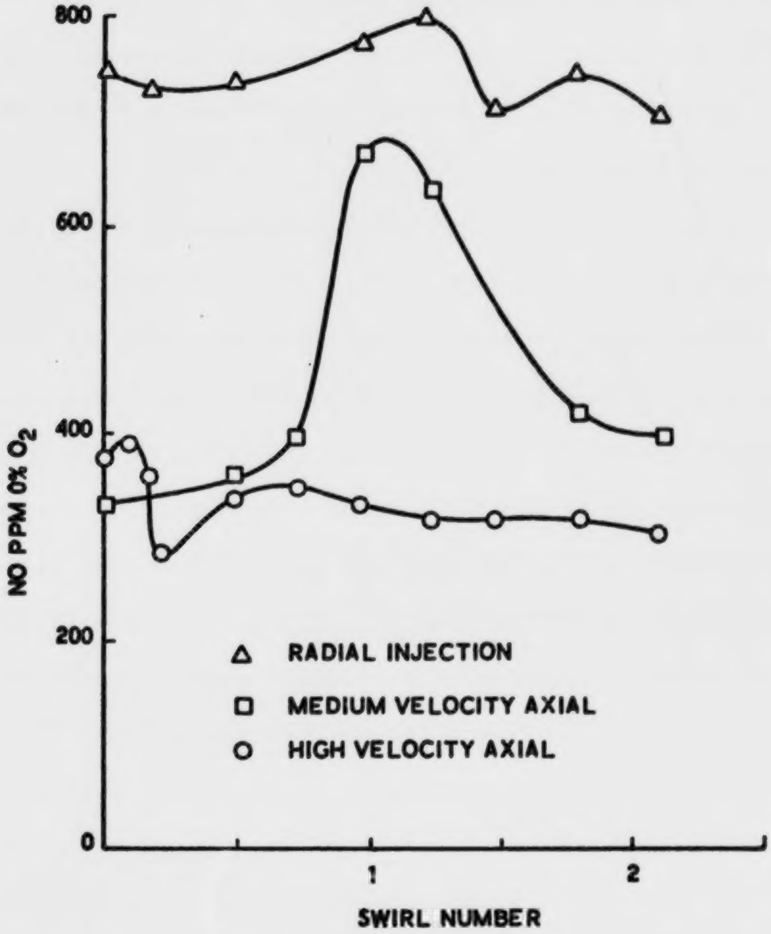
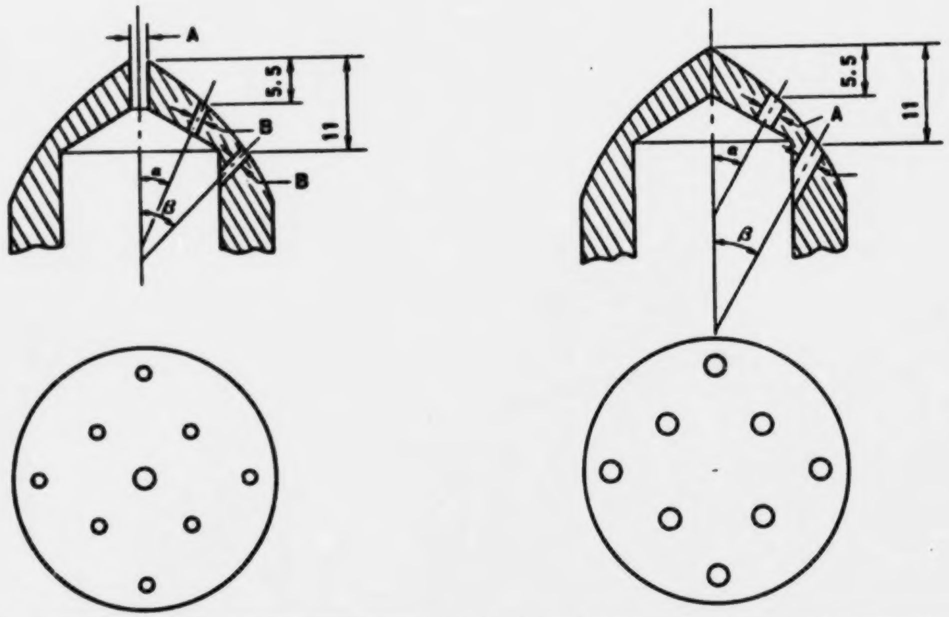


Figure 4. Range of NO Emissions Produced by Change of Fuel Injector (1.1% N_2 Coal, 300°C Preheat, 5% Excess Air)

combustion with rapid burnout. These combustion characteristics are attained in practice by using a fuel injection system which is similar to the radial fuel injector used in the subscale experiments. Thus, rapid fuel/air mixing provides satisfactory combustion conditions, but also promotes NO formation.

Subsequent experiments with a heavy fuel oil produced results which provide similar conclusions to those obtained with pulverized coal. Minimum NO emissions were obtained by maintaining the fuel oil as a single coherent jet on the flame axis, thus producing a long thin cylindrical flame similar in appearance to the low NO coal flame. Further investigations concentrated upon changing the design of the burner to maintain the required flame pattern, while attempting to reduce NO emissions to the minimum level possible. Japanese workers suggested an attractive technique for achieving these conditions which involved splitting the flame into several discrete sections(16) which gives the flame a flower petal arrangement. In these investigations this was achieved by placing a distributor tip over a standard Y-jet. Details of two types of distributor tips which have been investigated are presented in Figure 5; their emission characteristics, plotted as a function of secondary swirl intensity, are shown in Figures 6 and 7. It can be seen in Figure 6 that at low secondary swirl levels emissions from standard Y-jets are considerably higher than those obtained with distributor tips. However, as the swirl level is increased, the emissions from flames produced with distributor tips increase and, in



No.	α	β	A (mm)	B (mm)
4	25°	45°	2	1
5	25°	45°	4	2

No.	α	β	A (mm)	No. of Orifices
1	40°	40°	2.0	8
2	40°	40°	2.5	8
3	40°	40°	2.0	12

Figure 5. Details of Distributor Tips Used to "Split" Oil Flames

NOTE: All dimensions are in millemeters.

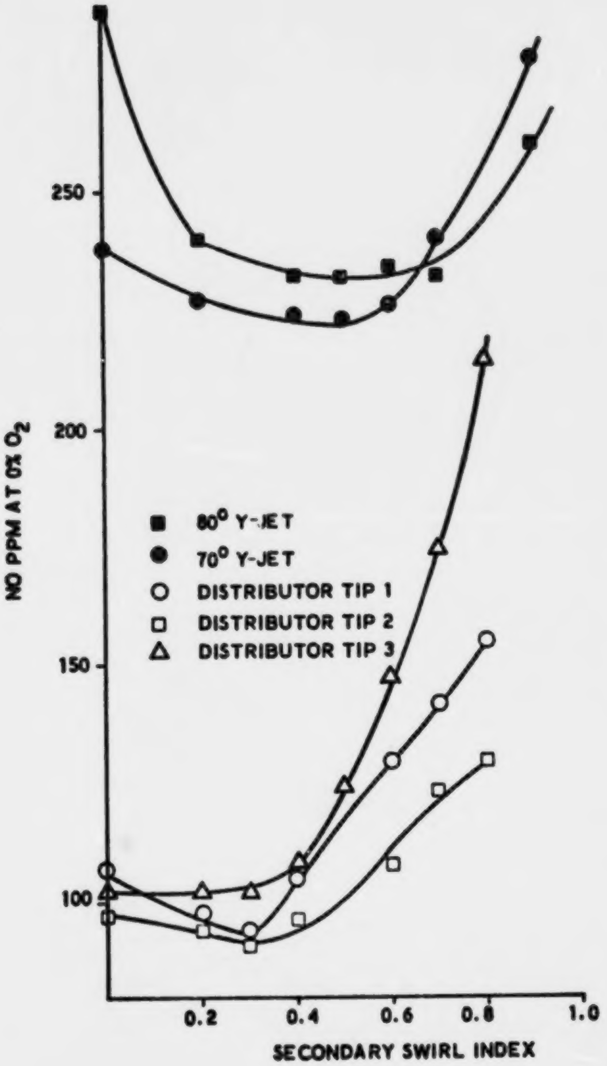


Figure 6. Emission Characteristics of Fuel Oil Flames (5% Excess Air, 300°C Preheat, Primary Swirl Vanes 30°)

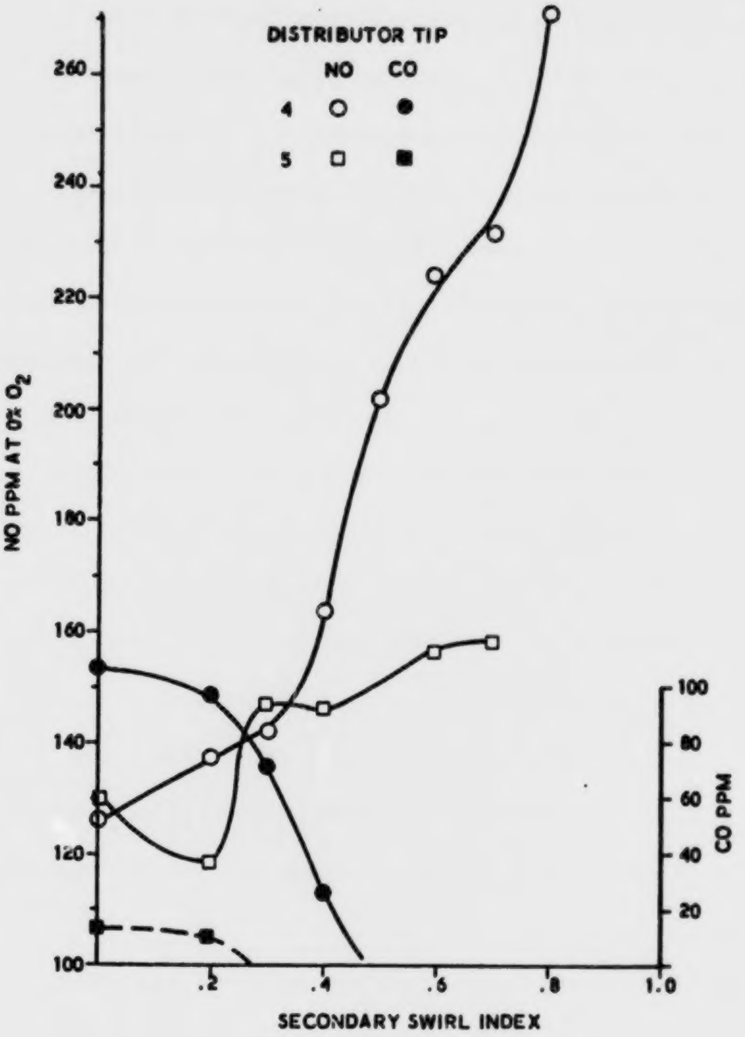


Figure 7. Emission Characteristics of Fuel Oil Flames (5% Excess Air, 300°C Preheat, Primary Swirl Vanes 30°)

one instance, approach the levels obtained with standard Y-jets. Distributor tips 4 and 5, which included an axial port, tended to produce considerable amounts of carbon monoxide at low swirl levels. As the swirl was increased, nitric oxide emissions increased and carbon monoxide emissions decreased. Further experiments indicated that the emission characteristics of fuel oil flames, produced with the distributor tip design shown in Figure 5, were not only dependent upon the configuration of the tip, but also upon other parameters such as the angle of the burner exit and the furnace wall temperature. From these investigations it can be concluded that this type of fuel injection system could be readily adapted for single flame applications. However, it may well be that the interaction between flames in multiple burner installations will negate any value with respect to reducing nitric oxide emissions. Consequently, further work is necessary to establish the influence of flame interactions on emissions before this type of tip can be recommended for use in multiple burner installations.

The characteristics of flames produced with the distributor tips were found to be different from those produced from the standard Y-jet. The extent of this difference can be judged by comparing the radial profiles of species concentration and temperature presented in Figure 8. Measured temperature, carbon monoxide, hydrogen, oxygen and methane concentrations are shown at an axial distance equal to 1.6 burner diameters from the face of the firing wall. It is evident from these radial profiles that there is considerable difference

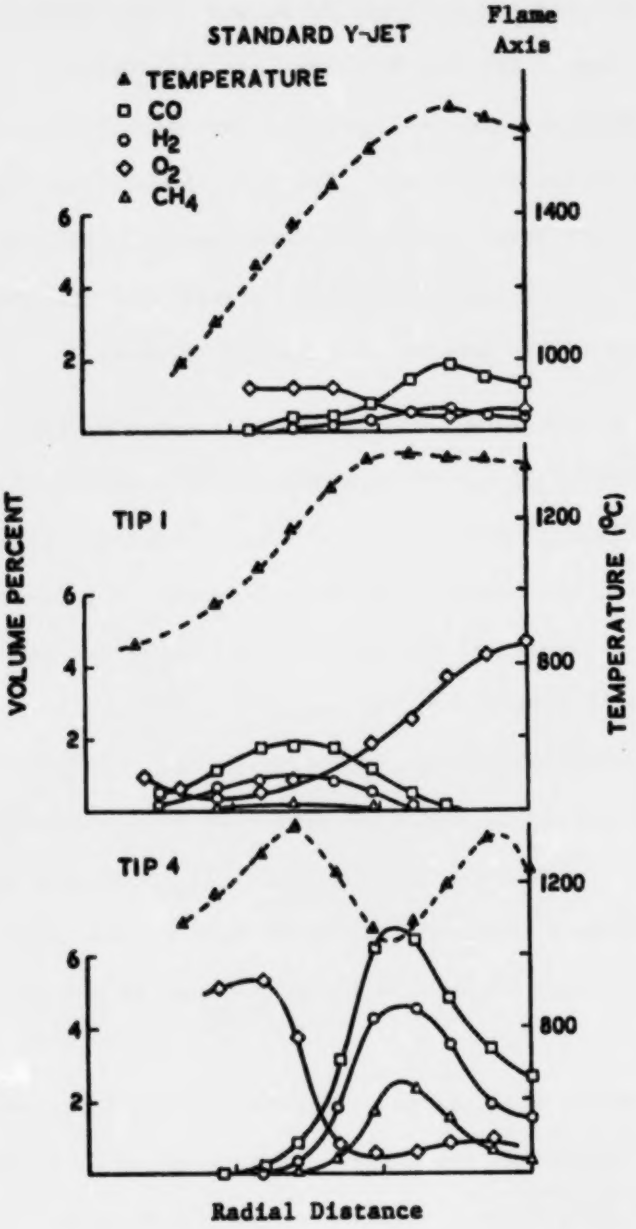


Figure 8. Radial Profiles of Temperature and Species Concentration

between the flame produced with the Y-jet and those produced with the distributor tips. The low NO flames are considerably longer, as shown by the carbon monoxide and hydrogen concentrations, and measured temperatures are much lower. The distributor tips also produce wider flames at this axial location. Consequently, utilization of this method of fuel oil injection would require that considerable attention be paid to the problem of flame impingement.

3.2 Division of the Total Air Supply into Separate Streams

The efficiency of staged combustion as a technique for reducing nitric oxide emissions from utility boilers is well established. The methods used in actual installation normally involve increasing the fuel flow through several of the burners, and using the remainder of the burners only to supply air. Experiments have been conducted at subscale to establish whether a combustion process can be effectively staged using the burner as a staging device by delaying mixing of all the fuel and air. Once more, the dual criteria of minimum emissions and acceptable flame characteristics were imposed upon these investigations since this type of control technique must be acceptable in existing equipment.

Investigations were carried out with both fuel oil and pulverized coal and it was found that the burner can be used as an effective staging device for both these fuels. Emission characteristics are shown in Figure 9 for two oil flames burning under identical furnace and burner

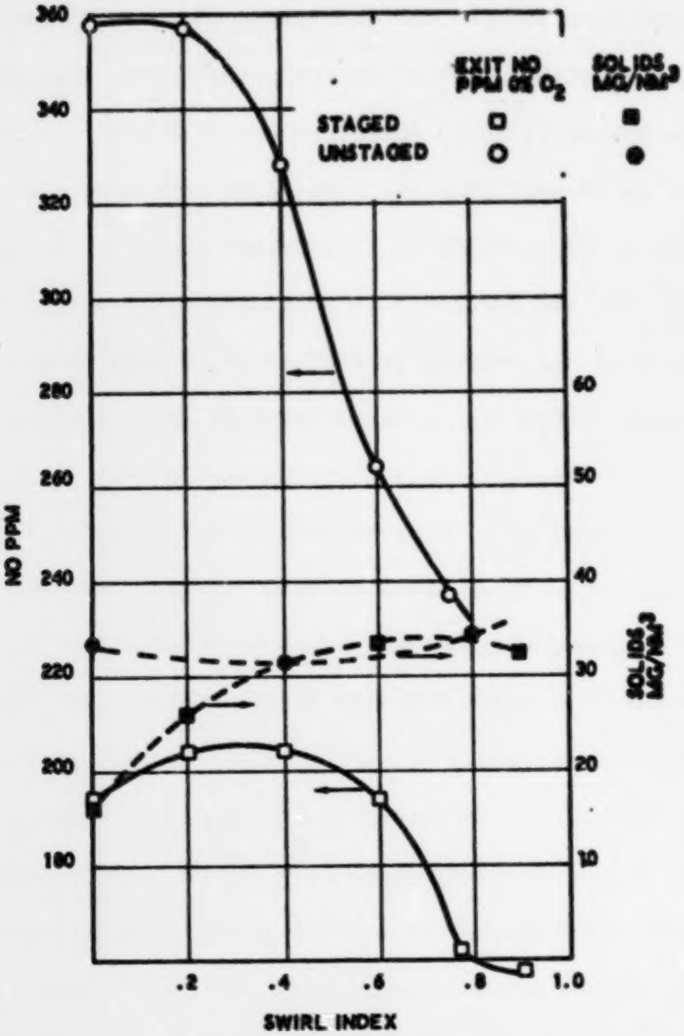


Figure 9. Reductions in NO Emissions From a Fuel Oil Flame by Diverting 35 Percent of the Total Air Through the Tertiary Injectors (5% Overall Excess Air, 300°C Preheat)

conditions except that the staged flame is 35 percent of the air delivered through eight parallel tertiary injectors. Included on the same figure are values of solid emissions measured with a β-Ray absorption device; it can be seen that the reduced NO emissions achieved by the staged burner are not accompanied by significant increases in the level of solid emissions. However, the reduced rate of fuel/air mixing which is believed to be the cause of the reduced production of NO also causes an increase in flame length. This can be appreciated by comparing the axial temperature and species concentrations distribution for staged and unstaged flames (see Figure 10). Temperatures in the unstaged flame are considerably higher than those measured under staged conditions. Flame length can be assessed either from visual observation, or it can be denoted by a particular carbon monoxide concentration. It is not possible from these measurements to ascertain whether the characteristics of the low NO produced by the staged oil flame are acceptable for normal boiler practice. However, these encouraging results indicate that the concept shows considerable promise, and that further investigations should be carried out under conditions more representative of large water walled boilers.

Similar experiments were carried out with pulverized coal to establish whether these techniques were applicable to solid fuels. Figures 11 and 12 give an indication of the success of this method of staging for reducing NO emissions from pulverized coal flames. As the

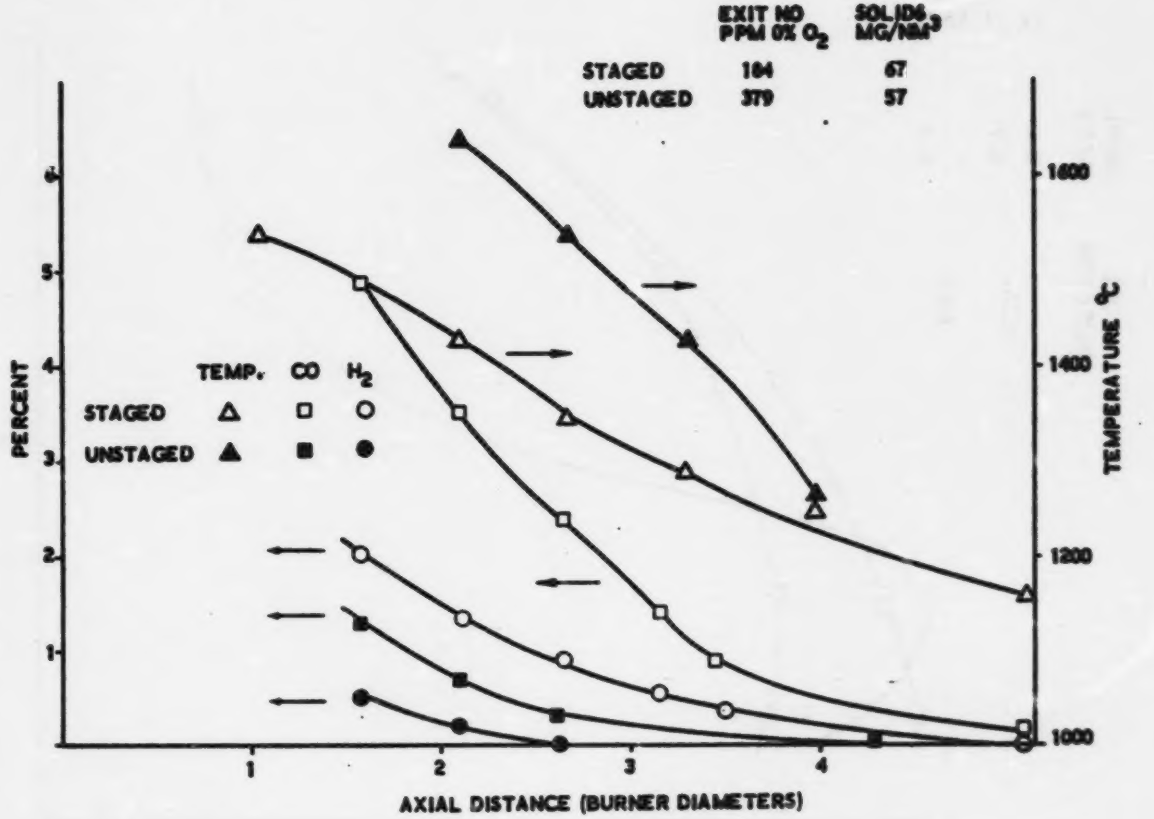


Figure 10. Comparison of Axial Profiles for Staged and Unstaged Oil Flames

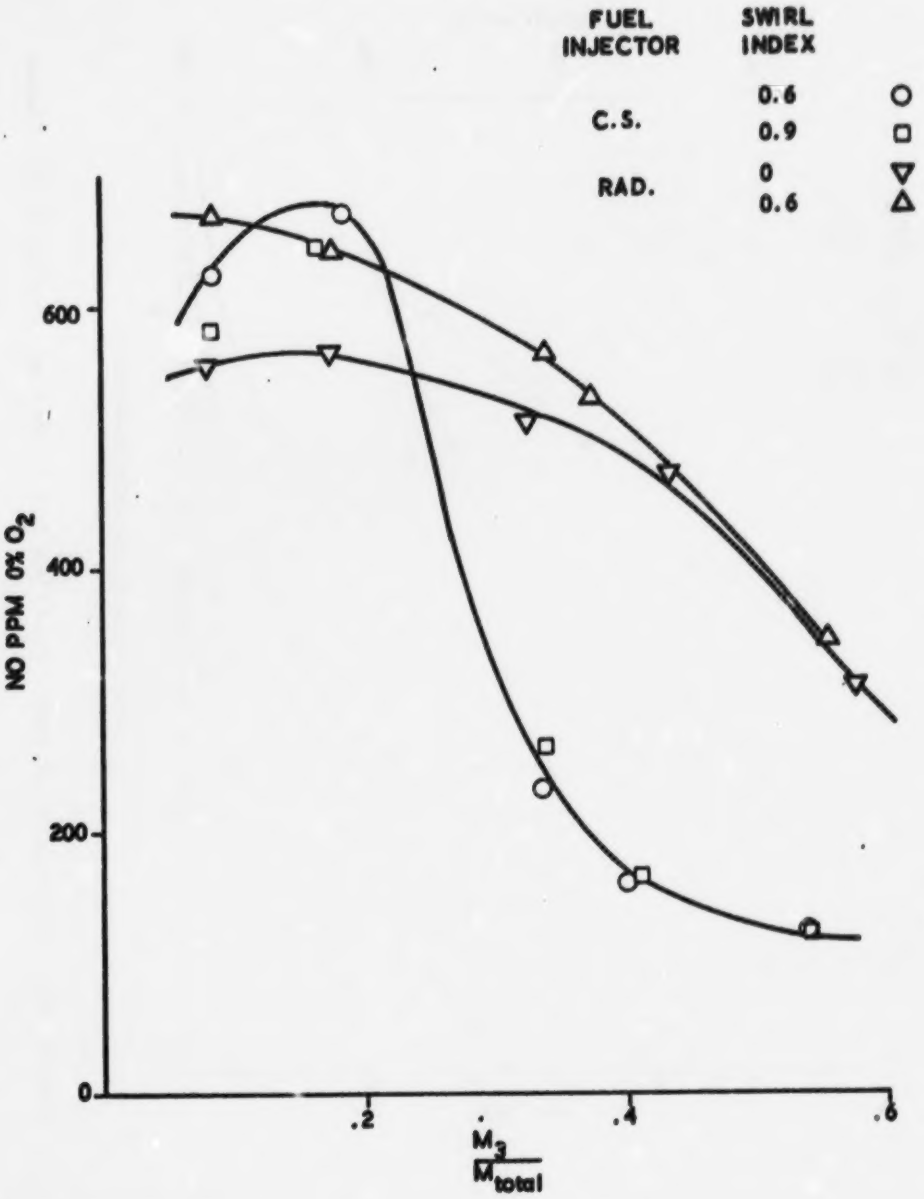


Figure 11. The Influence of Mass Flow of Tertiary Air ($\dot{M}_3$) on NO Emissions from Pulverized Coal Flames (5% Excess Air, 300°C Preheat, 950°C Wall)

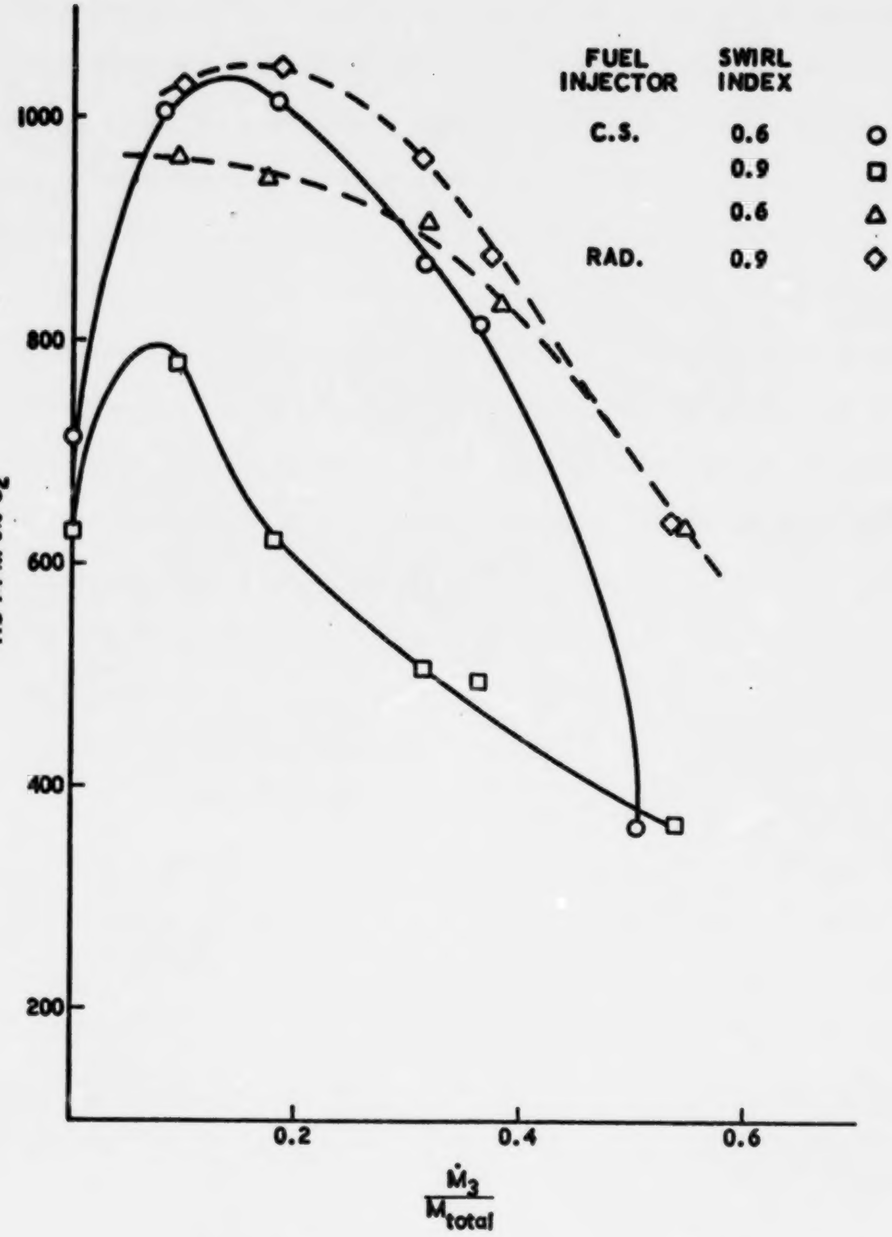


Figure 12. The Influence of Mass Flow of Tertiary Air ($\dot{M}_3$) on NO Emissions from Pulverized Coal Falmes (5% Excess Air, 300°C Preheat, 1250°C Wall)

percentage of air injected through the tertiary ports increases the NO emission decreases markedly*. It was found that the efficiency of staging depends both upon furnace wall temperature and upon the method of fuel injection. Figure 11 presents results obtained with an average wall temperature of approximately 950°C, whereas the furnace cooling load was reduced before the results presented in Figure 12 were obtained causing the wall temperature to increase to approximately 1250°C in the region of the burner. The influence of furnace wall temperature on emissions from pulverized coal flames had been observed before; temperature had a strong influence on NO emission from both natural gas and pulverized coal flames, but only a minor influence on emissions from oil flames. The increased wall temperature and subsequent increase in the temperature of recirculated gases produce an increase in NO emission of about 200 ppm for the staged condition. It is contended that the influence of the method of fuel injection on the efficiency of staging is associated with the residence time of the coal particles within the rich primary zone. The intensity of swirl in the secondary air appears to have a negligible influence upon nitric oxide emissions at high staging levels. Under all circumstances carbon burnout was virtually complete at the exit of the furnace for both staged and unstaged flames. Figure 13 compares the influence of tertiary air injection on carbon monoxide emissions for the two methods of fuel injection with the lower furnace wall temperatures. It can be seen that staging has no influence upon CO emissions from the radial fuel injector; however, the six-fold decrease in NO emission with the coal spreader type injector is accompanied by a three-fold increase in carbon monoxide emissions at high levels of burner staging. The experiments made no attempt to optimize conditions for low CO emissions which could probably be achieved by further minor modifications to the fuel injector.

---

*The results refer to two methods of fuel injection, radial (rad) and a scaled down version of a fuel injector typical of those used in practice (c.s).

3.3 Investigations Involving Petroleum Coke

Petroleum coke is a high nitrogen, low volatile, low ash solid which was burned under identical conditions to those for burning pulverized coal. NO emissions from petroleum coke were found to be generally lower than those from coal. This can be appreciated by comparing the influence of firing rate on nitric oxide emissions for the two fuels (see Figure 14). At the nominal firing rate of approximately 5 x 10^6 BTUs per hour with 300°C preheat and 15 percent excess air, emissions from pulverized coal flames are approximately twice those of petroleum coke when both fuels are injected to ensure rapid mixing between the fuel and combustion air. Increasing the firing rate increases the bulk gas temperature within the furnace which causes an increased NO emission from both fuels. However, the influence of firing rate is much stronger with pulverized coal, particularly at high firing rates, once more indicating that the temperature environment of pulverized coal flames has a very strong influence upon nitric oxide production. The profound influence of

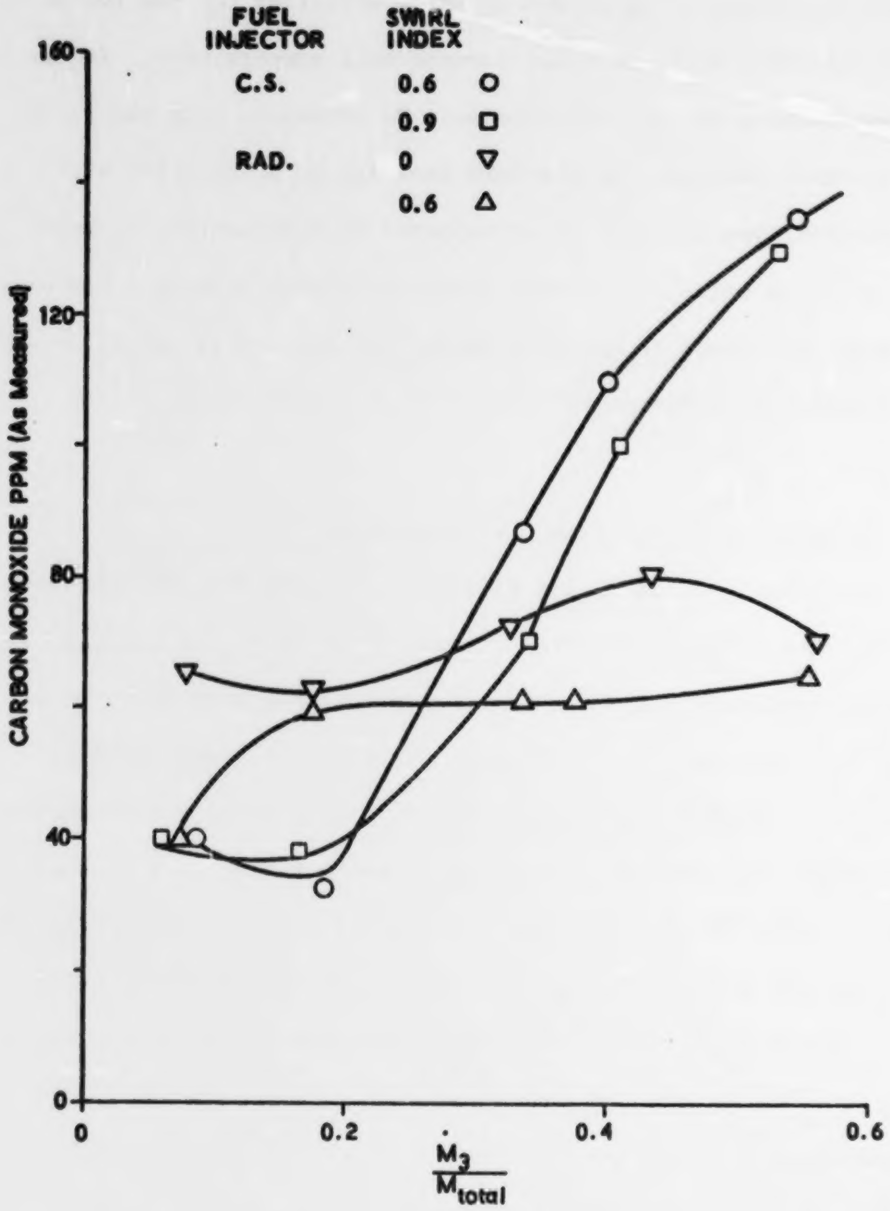


Figure 13. The Influence of Mass Flow of Tertiary Air ($\dot{M}_3$) on Carbon Monoxide Emissions (5% Excess Air, 300°C Preheat, 950°C Wall)

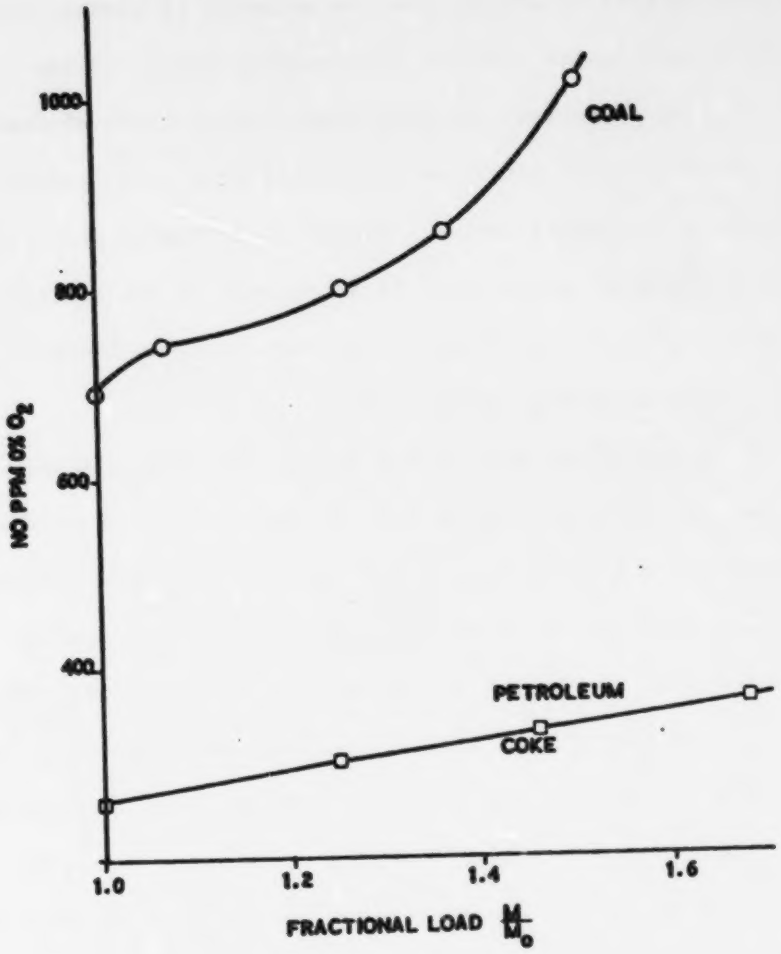


Figure 14. Nitric Oxide Emissions as a Function of Load for Coal and Pulverized Coke

the method of fuel injection upon the emission of nitric oxide from pulverized coal flames has been discussed earlier. It was found that emissions from petroleum coke were almost independent of fuel injector type. Emissions from petroleum coke could also be decreased by using the burner as a staging device. Figure 15 indicates that emissions could be reduced by almost half if 50 percent of the air was supplied through the tertiary injectors. This reduction was found to be independent of the secondary swirl level.

Since petroleum coke is a low volatile, high nitrogen solid, comparison of the results presented in Figure 14 could be used to provide support for the hypothesis that volatile nitrogen compounds are responsible for fuel NO formation in pulverized coal flames. This support would be based upon the assumption that the fuel nitrogen compounds in coal and oil are similar and that their evolution from the solid particle would be similar under similar time/temperature histories. At this time these are rather sweeping assumptions and, although the results tend to support the hypothesis, they cannot be considered as definitive.

4.0 SCALE-UP CRITERIA FOR LOW EMISSION, HIGH EFFICIENCY BURNERS

The results of the subscale experiments discussed in the previous section demonstrated that low emission, high efficiency burners could be operated with both pulverized coal and heavy fuel oil. Burner designs which reduce the rate of coal/air mixing (and thus NO emissions) are already being tested in large utility boilers. The

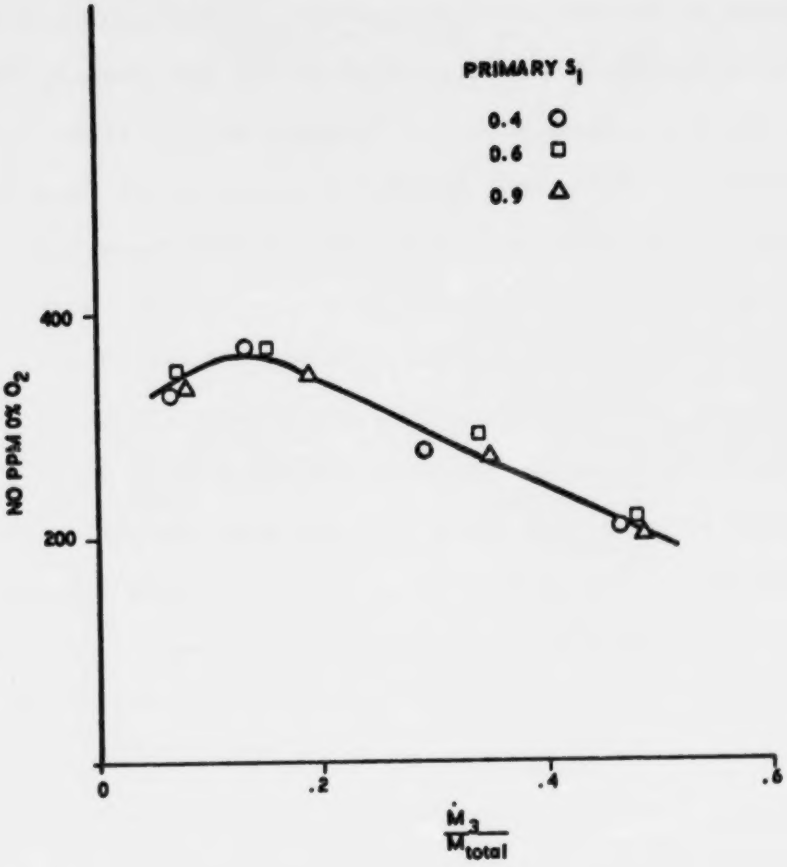


Figure 15. The Influence of Burner Staging on NO Emissions from Petroleum Coke Flames

relevance of the subscale investigations to practical situations can be criticized on three points. Firstly, all the subscale tests were conducted in a horizontal tunnel furnace where the flames fired horizontally, and the exit of the furnace was on the flame axis. The recirculation patterns were very different from those likely to be encountered in large industrial and utility boilers. Secondly, the results refer to single burner conditions, and the influence of flame interactions on NO formation is ill understood. Thirdly, it has not been established whether the principles discussed in Section 2.0 of this paper are suitable for scaling to ensure their applicability in practical boilers. Investigations to be carried out under EPA Contract 68-02-1488 with Ultrasystems have been planned to answer all of these questions.

Emission control techniques which reduce pollutant emissions at the expense of fuel economy or operating efficiency are not only financially unacceptable, but they are also socially irresponsible. The overall objective of this new EPA program is to design, construct, and test low emission, high efficiency burners in a size suitable for use in industrial and utility boilers. This research program will:

- Design and construct a test facility which will allow large scale burners to be tested under conditions representative of those to be encountered in industrial practice.
- Establish the influence of burner/burner and burner/furnace interactions on pollutant formation in large scale fossil fuel flames.

- Establish scaling laws to ensure that design methods are available to enable low emission, high efficiency burners to be constructed for a wide range of firing rates.
- Ensure that reduced pollutant emission is not accomplished at the expense of reduced thermal efficiency and increased operating costs.
- Establish the optimum firing method for dual firing of low BTU gas and pulverized coal in both and single and multiple burner arrays.
- Specify burner designs which are suitable for extensive testing in industrial and utility boilers.

This program will be carried out with three fuels: pulverized coal, low BTU gas, and heavy fuel oil, burned singly and in combination. The investigations will include both input/output measurements, and detailed flame probing to establish the characteristics of the low emissions flames.

The goals of the program can only be satisfied if a flexible experimental facility is available. The focal point of this facility must be a combustor which simulates wall temperature and recirculation patterns typical of modern industrial and utility water wall boilers. It must also allow rapid interchange of multiple burner arrays to enable an assessment of the influence of such parameters as burner/burner spacing and the distance of burners from adjacent walls on pollutant emissions. Figure 16 shows a cutaway sketch of a modular spray-cooled combustor which has been designed to satisfy the requirements of this project by providing the representative environment and the required degree of flexibility. The major features of this combustor

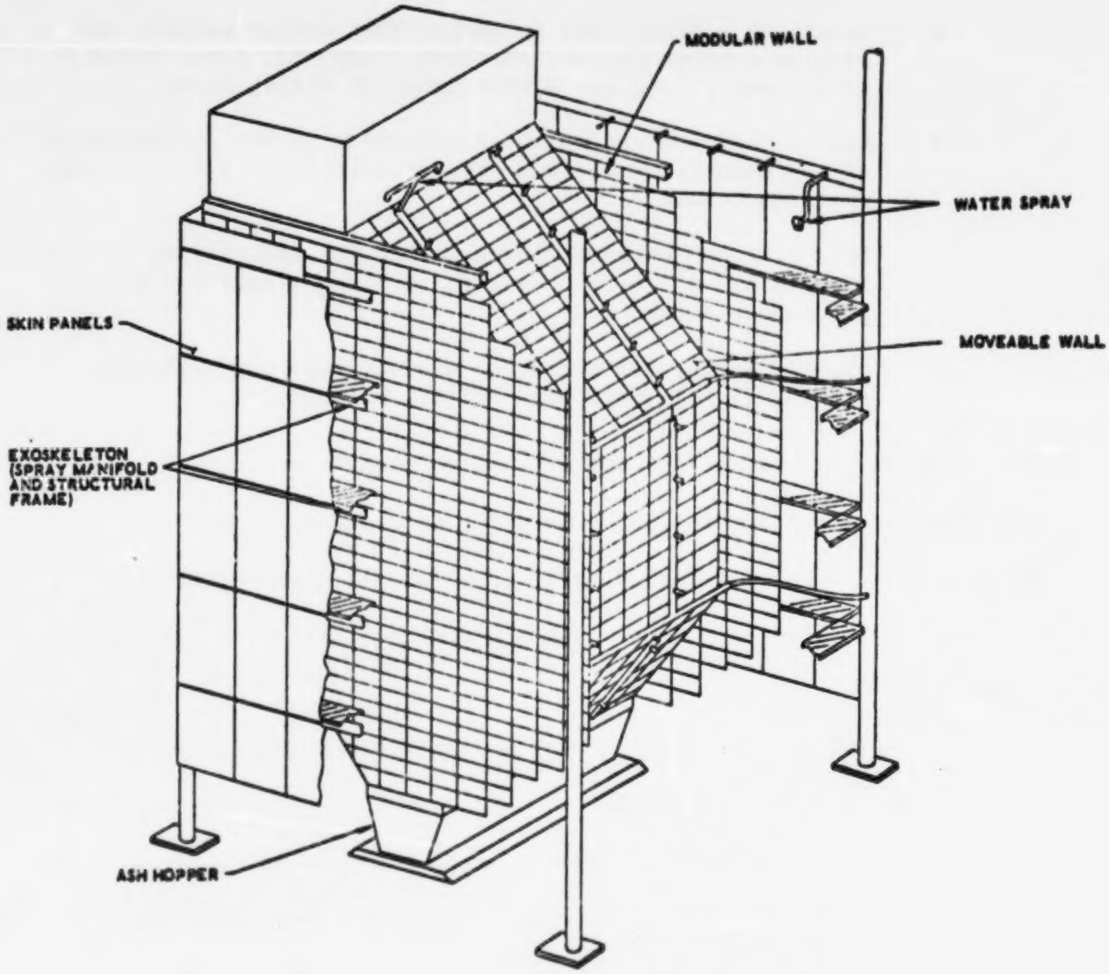

MODULAR WALL
WATER SPRAY
SKIN PANELS
MOVEABLE WALL
EXOSKELETON (SPRAY MANIFOLD AND STRUCTURAL FRAME)
ASH HOPPER

Figure 16. Cutaway Sketch of a Modular Moveable Wall Spray Cooled Combustor

are its low thermal inertia; up to five burners can be placed anywhere on the firing wall; one wall of the combustor is moveable, thus allowing the influence of burner/furnace interactions to be established; the modular construction allows probes to be inserted in almost any location; and Figure 17 presents a schematic showing the arrangement of a flame probe and the combustor wall. The entire facility will stand alone, will be dedicated to this project, and will have a firing rate capacity for single burners of 120 x 10^6 BTU/hr. Multiple burner investigations will be able to be carried out with a maximum of five burners firing at a total rate of 60 x 10^6 BTU/hr. Three single burner sizes of 12, 60 and 120 x 10^6 BTU/hr will be tested and their characteristics established, thus providing information on scale up criteria of low emission burners. Some idea of the extent of this test facility can be gained from the general layout which is presented in Figure 18, which gives the approximate location of the heat exchanger, pulverizer, steam supply and propane reformers which will be used to provide low BTU gas. This program is presently in the design phase; it is expected that construction of the test facility will commence in the near future.

5.0 CONCLUSION

This paper has presented experimental information which clearly demonstrates that low emission, high efficiency burners can be operated in subscale. At this time it is pertinent to consider the EPA's

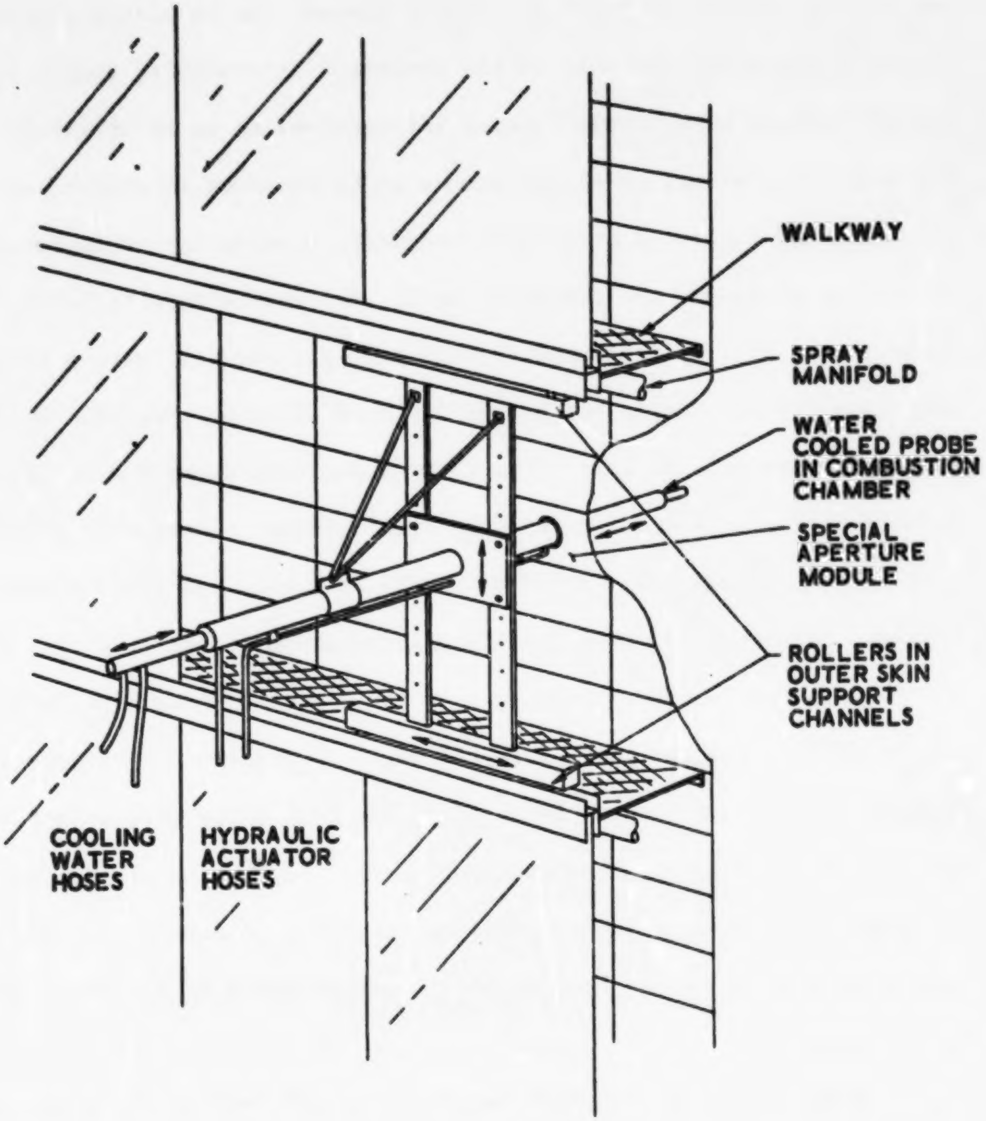

WALKWAY
SPRAY MANIFOLD
WATER COOLED PROBE IN COMBUSTION CHAMBER
SPECIAL APERTURE MODULE
ROLLERS IN OUTER SKIN SUPPORT CHANNELS
COOLING WATER HOSES
HYDRAULIC ACTUATOR HOSES

Figure 17. Schematic Representation Showing the Location and Actuating Mechanism of Flame Probe

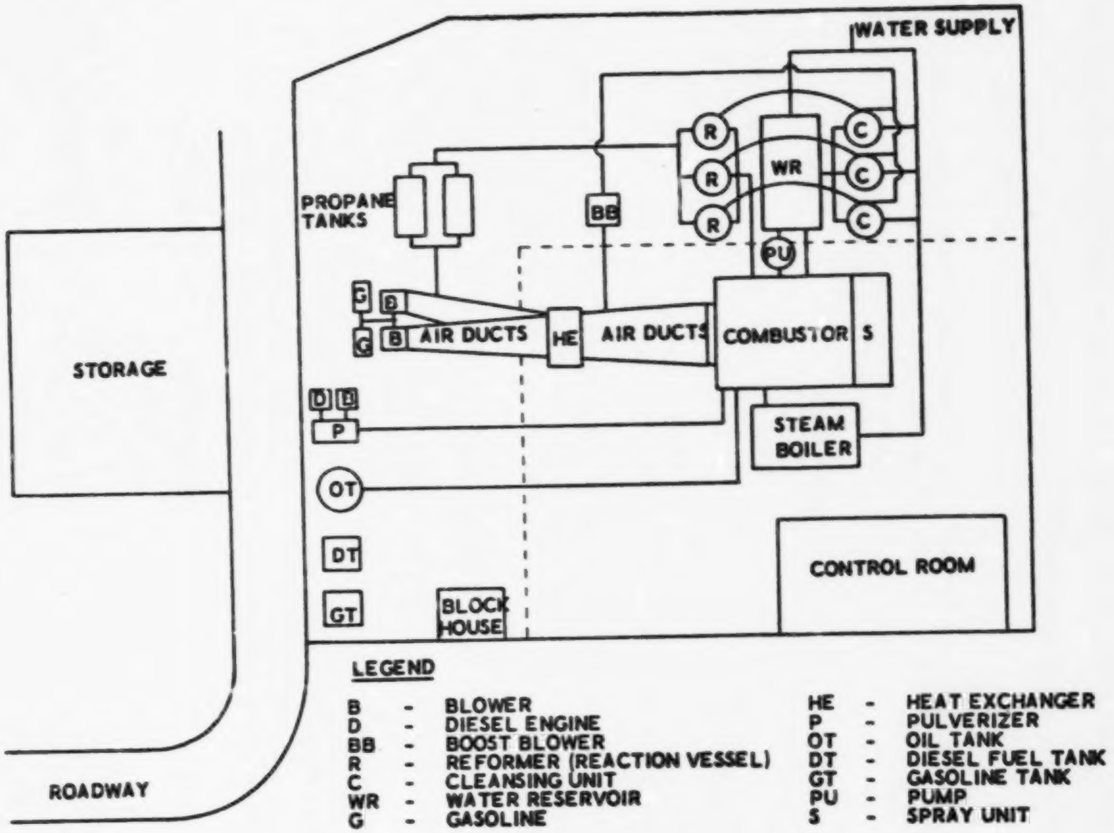

WATER SUPPLY
PROPANE TANKS
STORAGE
ROADWAY
BB
R
R
R
WR
C
C
C
PU
G
B
G
B
AIR DUCTS
HE
AIR DUCTS
COMBUSTOR
S
D
B
P
STEAM BOILER
OT
DT
GT
BLOCK HOUSE
CONTROL ROOM
LEGEND
B - BLOWER
D - DIESEL ENGINE
BB - BOOST BLOWER
R - REFORMER (REACTION VESSEL)
C - CLEANSING UNIT
WR - WATER RESERVOIR
G - GASOLINE
HE - HEAT EXCHANGER
P - PULVERIZER
OT - OIL TANK
DT - DIESEL FUEL TANK
GT - GASOLINE TANK
PU - PUMP
S - SPRAY UNIT

Figure 18. General Layout of Test Facility

projected long and short term goals for utility boilers as stated by Lachappelle, Bowen and Stern.(17)

Table 1. Project Short and Long Term Goals for NO_x Control from Utility Boilers(17)

	ppm at 3 percent O_2	
	1980 Goal	1985 Goal
Gas	100	50
Residual Oil	150	90
Coal	200	100

The short term goals can be achieved at present under controlled experimental conditions. It remains to be seen whether they are achievable in practical operating plants. Section 4.0 of this paper discussed plans to construct a test facility which will provide much needed information on the characteristics of low emission combustion systems for coal and heavy fuel oil. This information will give confidence in the design concepts and give a clear indication of whether the goals presented in Table 1 are achievable.

REFERENCES

1. Bowman, C.T., The Fourteenth Symposium (International) on Combustion, p. 729, The Combustion Institute, 1973.

2. Sternling, C.V. and Wendt, J.O.L., "Kinetic Mechanisms Governing the Fate of Chemically Bound Sulfur and Nitrogen in Combustion." Shell Development Company, Emeryville, California, EPA-650/2-74-017 (NTIS No. PB 230-895/AS), August 1972.

3. Fenimore, C.P., Thirteenth Symposium (International) on Combustion, p. 373, The Combustion Institute, 1971.

4. Heap, M.P., Lowes, T.M. and Walmsley, R., "Nitric Oxide Formation in Pulverized Coal Flames," Combustion Institute European Symposium, p. 493, Academic Press, (1973).

5. Heap, M.P., Lowes, T.M., "Burner Design Optimization to Control NO_x Emissions," Presented at the "Coal Combustion Seminar," Environmental Protection Agency, Research Triangle Park, N.C., June 19-20, 1973, EPA-650/2-73-021, (NTIS No. PB 224-210/AS) September 1973.

6. Pershing, D.W., Martin, G.B. and Berkau, E.E., "Influence of Design Variables on the Production of Thermal and Fuel NO_x from Residual Oil and Coal Combustion." Paper presented at the AIChE 66th Annual Meeting, Philadelphia, 1973.

7. Wendt, J.O.L., Sternling, C.V., and Matovich, M.A., Fourteenth Symposium (International) on Combustion, p. 697, The Combustion Institute, 1973.

8. Bartok, W., Engleman, V.S. and del Valle, E.G., "Laboratory Studies and Mathematical Modeling of NO_x Formation in Combustion Processes," Esso Research and Development Co., EPA report APTD 1168 (NTIS No. PB 211-480), 1972.

9. Sarofim, A.F., Williams, G.C., Modell, M. and Slater, S.M., "Conversion of Fuel Nitrogen to Nitric Oxide in Premixed and Diffusion Flames." Paper presented at the AIChE 66th Annual Meeting, Philadelphia, 1973.

10. Myerson, A.L., Fifteenth Symposium (International) on Combustion, p. 1085, The Combustion Institute, 1975.

11. Flower, W. L., Hanson, R. K. and Kruger, C. H., Fifteenth Symposium (International) on Combustion, p. 823, The Combustion Institute, 1975.

12. Cernansky, N. P. and Sawyer, R. F., Fifteenth Symposium (International) on Combustion, p. 1039, The Combustion Institute, 1975.

13. Heap, M. P., et al. "Burner Criteria for NO_x Control, Volume I- Influence of Burner Variables on NO_x in Pulverized Coal Flames." International Flame Research Foundation, IJmuiden, Holland, EPA-600/2-76-061a (NTIS No.-Later), March 1976.

14. Leuckel, W., Swirl Intensitites, Swirl Types and Energy Losses of Different Swirl Generating Devices, Doc. G02/a/16, IFRF, IJmuiden, Holland (1968).

15. Heap, M. P., Lowes, T. M., and Martin, G. B., "Fluid Mechanics of Combustion," p. 75, The American Society of Mechanical Engineers, April 1974.

16. Tsuji, S., Tsukada, M. and Asai, M., Ishikawima-Harima Engineering Review 13, p. 227 (1973).

17. Lachapelle, D. G., Bowen, J. S., and Stern, R. D., "Overview/ Environmental Protection Agency NO_x Control Technology for Stationary Combustion Sources." Presented at 67th Annual Meeting of the AIChE, December 1974.

1:30 p.m.

The Optimization of Burner Design Parameters To Control NO_x Formation in Pulverized Coal and Heavy Oil Flames

Dr. Michael P. Heap, Ultrasystems

Q: Mike, I didn't understand when you said that you added methane. When you added it the NO went up?

A: If you were to take an average value of what you would expect, if you were just to prorate it, you would find out that you didn't get any advantage by having the gas and the coal fired together. And you could see that instead of methane if you put in blast furnace gas, which did also contain a small amount of methane, that the emissions were lower than what you would have expected from just the algebraic sum of the two. I believe it has something to do with the heating rate of the particles.

Q: That was what was bothering me. Because I had just an intuitive feeling that if you nave a fast heating rate and get the stuff hot in the absence of oxygen you can get the nitrogen to combine to molecular nitrogen N_2.

A: In fact, the burner situation was such that you mixed the coal very efficiently with the air anyway. You are just driving off more fuel nitrogen where the oxygen was available. The same kind of effect appears to happen if you increase the temperatures considerably.

PILOT SCALE INVESTIGATION OF COMBUSTION MODIFICATION TECHNIQUES FOR NO_x CONTROL IN INDUSTRIAL AND UTILITY BOILERS

by

R. A. Brown
C. B. Moyer
H. B. Mason

Aerotherm/Acurex Corporation
Mountain View, California

D. G. Lachapelle

Environmental Protection Agency
Research Triangle Park
North Carolina

Preceding page blank

PILOT SCALE INVESTIGATION OF COMBUSTION MODIFICATION TECHNIQUES FOR NO_x CONTROL IN INDUSTRIAL AND UTILITY BOILERS*

R. A. Brown, C. B. Moyer, H. B. Mason
Aerotherm Division/Acurex Corporation
Mountain View, California

D. G. Lachapelle
Environmental Protection Agency
Research Triangle Park
North Carolina

INTRODUCTION

As part of a continuing effort to provide better NO_x control for stationary sources, the EPA has conducted supporting laboratory experiments to define NO_x formation mechanisms, to identify control techniques, and to guide development work on commercial equipment. The EPA facility described here is an important component of this support effort. Unlike most laboratory units, it provides a fairly realistic modeling of the geometry and aerodynamics of large multi-burner boilers. It can fire a wide variety of fuels, including pulverized coal, and can simulate almost all combustion modifications for NO_x control:

---

*This project was funded at least in part with Federal funds from the Environmental Protection Agency under contract number 68-02-1503, 68-02-1318, and 68-02-1861. The content of this publication does not necessarily reflect the views or policies of the U.S. Environmental Protection Agency, nor does mention of trade names, commercial products, or organizations imply endorsement by the U.S. Government.

load changes, excess air control, staging, biasing, flue gas recirculation, reduced air preheat, and burner modifications.

The important goals for this facility will include:

- Further definitions of staging and biasing in wall firing of high nitrogen fuels (coal and oil) to provide a more complete mapping than presently available of the effects of first and second stage stoichiometries, residence times, and mixing rates, so as to
    - (a) Guide experiments of full scale equipment toward the most effective retrofit technology
    - (b) Point the way toward second generation or optimized NO_x control including advanced combined techniques, for new designs
- A duplicate set of goals for tangentially fired units, but with the additional topic of burner modifications, an aspect not being fully investigated elsewhere
- Exploration of NO_x control techniques for mixed fuel firing (such as high and low nitrogen fuels) and for waste fuels
- A quick look at the emission levels of other pollutants such as sulfates and nitrates, as influenced by NO_x controls

This paper describes the physical features and capabilities of the EPA research test furnace facility and the tentative test plans to achieve these goals.

FACILITY DESCRIPTION

Figure 1 shows the furnace facility. The multifuel/multiburner furnace is one of the most versatile pieces of equipment of this size and type in the United States. Table 1 lists the components and capabilities relevant to the research program, and the ranges over which parameters may be varied.

The furnace may have both front-wall or opposed-wall firing, with from one to five burners in each wall. Alternatively, the furnace can accept tangential burners to simulate the design practice of Combustion Engineering. The combustion chamber can run with or without internal cooling tubes.

The front wall fired burners are in two sizes, 300,000 Btu/hr (five each) and 1.5 x 10^6 Btu/hr (two each). These burners, shown in Figure 2, are patterned after the IFRF design, with variable swirl and provision to change many other parameters. Eight CE type burners, shown in Figure 3, are also provided. These burners are capable of variable tilt (±30°), variable yaw (±10°), have interchangeable air sleeves and fuel nozzles and are capable of being fired on gas, oils or pulverized coal. The relative position of the two banks of corner fired burners is the same as the Combustion Engineering burners.

Four identical heat exchangers designed to cool a heat input of three million Btu/hr to 400°F are stacked atop the main combustion

1. Combustion chamber (39" cube)
2. Ignition and flame safeguard
3. Observation ports
4. Ashpit
5. 1.5 x 10^6 Btu/hr IFRF burner
6. C.E.-type corner fired burners
7. 3200°F refractory
8. Heat exchange sections
9. Drawer assemblies
10. Staged injection ports

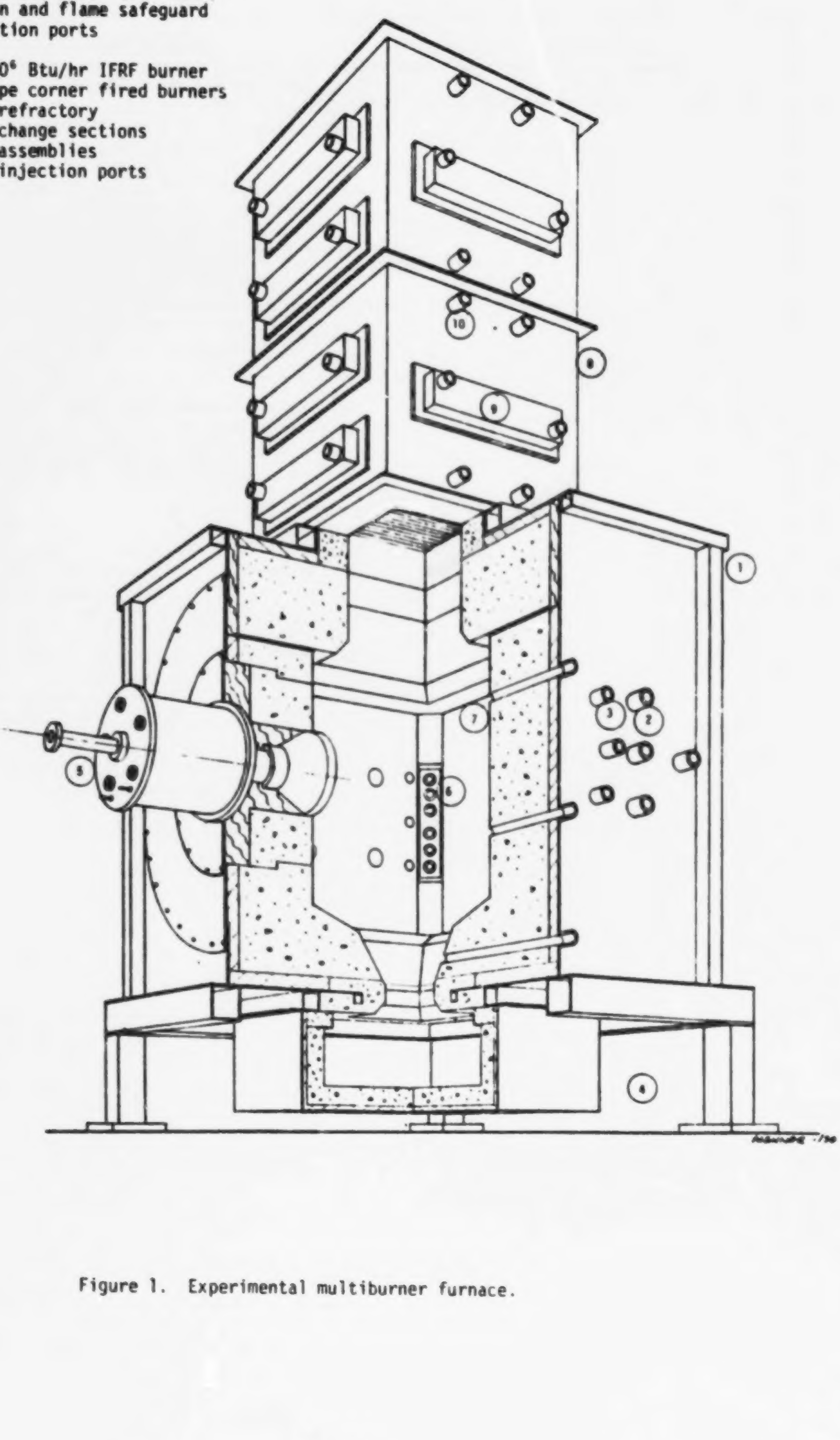


Figure 1. Experimental multiburner furnace.

TABLE 1. PRINCIPAL COMPONENTS AND CAPABILITIES

Component	Description
Main Furnace Combustion Chamber	Max. refractory temp: 3200°F Volume: 47 ft^3 View ports: 5, 3" dia., 1 10" x 10" bottom with periscope Ignition ports: 6, 1" dia. Burner blocks and plugs: 1, 5 hole, 28" dia. 1, single hole, 28" dia. 8, corner, "x" Burner mounting: 1-5 horizontal opposed 1-5 wall fired 4, 8 tangentially fired
Ash Pit	Volume: 8 ft^3 Max. temp: 2600°F
Heat Exchangers	Sections: 4 refractory lined Max. temp: 3000°F Inside dimensions: 25x25x32" high Drawers: 24 with 20-5/8" U tubes/DWR - removable Length of Dwr.: 32" Coolant: Dowtherm Access ports: 4/section, 1" dia. Mixing section: 6" above and below drawers (access ports are located in those sections) Max. heat abs.: 2.2 x 10^6 Btu/hr Wt.: 1500#/section w/o drawers
Burners	2 - 1.5 x 10^6 Btu/hr Aerotherm/IFRF 5 - 300,000 Btu/hr Aerotherm/IFRF • Interchangeable fuel tips • Interchangeable quarls • Variable swirl • Air sleeves to change velocity 8 - 375,000 Btu/hr Aerotherm corner fired • Three identical circular air & fuel inlets/burner • ±30° tilt - all inlets ganged • ±10° yaw - all outlets ganged • Interchangeable air sleeves for each port • Interchangeable fuel nozzles
Air Supply Primary	• 800 SCFM @ 8 psig • Aftercooler: 70°F dew point @ 8 psig • Cold control valve & orifice; separate heater
Secondary	• Hot control valves & orifices

TABLE 1. (Continued)

Component	Description
	• Individual control & measurement to 16 lines, 8 on each side of the furnace. Allows flow control of secondary air to each IFRF burner and control of annular and secondary air flows to the corner fired burners.
Staged Air	• Staged air manifold parallel to heat exchanger stack. Mixes hot secondary and cold secondary air to achieve any temperature up to the secondary air temperature. Presently only total staged air is controlled.
Heaters	• Secondary air 200 kw max. Temperature at the burner: 800°F • Primary air heater 12 kw max. Temperature at the burner: 250°F • Continuous control from 70°F to the maximum temperature for 10:1 flow range
Flue Gas Recirculation	• Take off point downstream of baghouse • Max. temperature: 400°F • Max. flow: 120 SCFM • Max. pressure: 2 psig • Max. firing rate permissable at these conditions: 1.5 x 10^6 Btu/hr @ 10% excess air • Present introduction point is in the secondary air line downstream of the secondary air heater. (Simple modification could be made to introduce the flue gases in the stage air, primary air or individual burners. • No FGR heater at this time
Oil Delivery System	• Up to 25 gal/hr on #2 or #6 oil • Single pumping & supply system for both oils • Max. temperature #6: 220°F at the nozzles • Two oil manifolds with 8 taps each on either side of the furnace • Quick disconnect fittings at the manifold and burners • Flow control valves to each burner • Max. pressure: 250 psig

TABLE 1 (Concluded)

Component	Description
Gas System	• Up to 3000 ft^3/hr @ 25 psig • Manifold with quick disconnects, 8 outlets on each side of the furnace • Shutoff ball valves for each tap on the manifold and needle control valves for each burner inlet
Coal System	• Up to 250 lbs/hr of pulverized coal • Ten delivery lines to two manifolds, one on each side of the furnace. Five flexible lines on each manifold deliver pulverized coal to one to five burners. The small lines must be recombined when firing the larger burners. • The coal and primary air flow rates are controlled and measured to each of the delivery lines. Uniform distribution is obtained from a fluidized bed distributor. • Bagged pulverized coal is fed into a bagdump from the second floor level and into a 50 ft^3 hopper. This represents about a 1 day supply of coal. • The fuel flow may be stopped in the event of a flame-out or unstable condition through a solenoid operated air purge system. This purge system is controlled manually or by the flame safeguard system.
Dowtherm System	• Two Dowtherm-to-air heat exchangers can remove up to 2.5 x 10^6 Btu/hr from the Dowtherm • A bypass arrangement around these coolers allows control of the heat removal rate.
Induced Draft Fan	• An induced draft fan with bypass allows control of the back pressure in the combustion chamber to ±2" H_2O over the full range of firing rates.

Reproduced from best available copy.

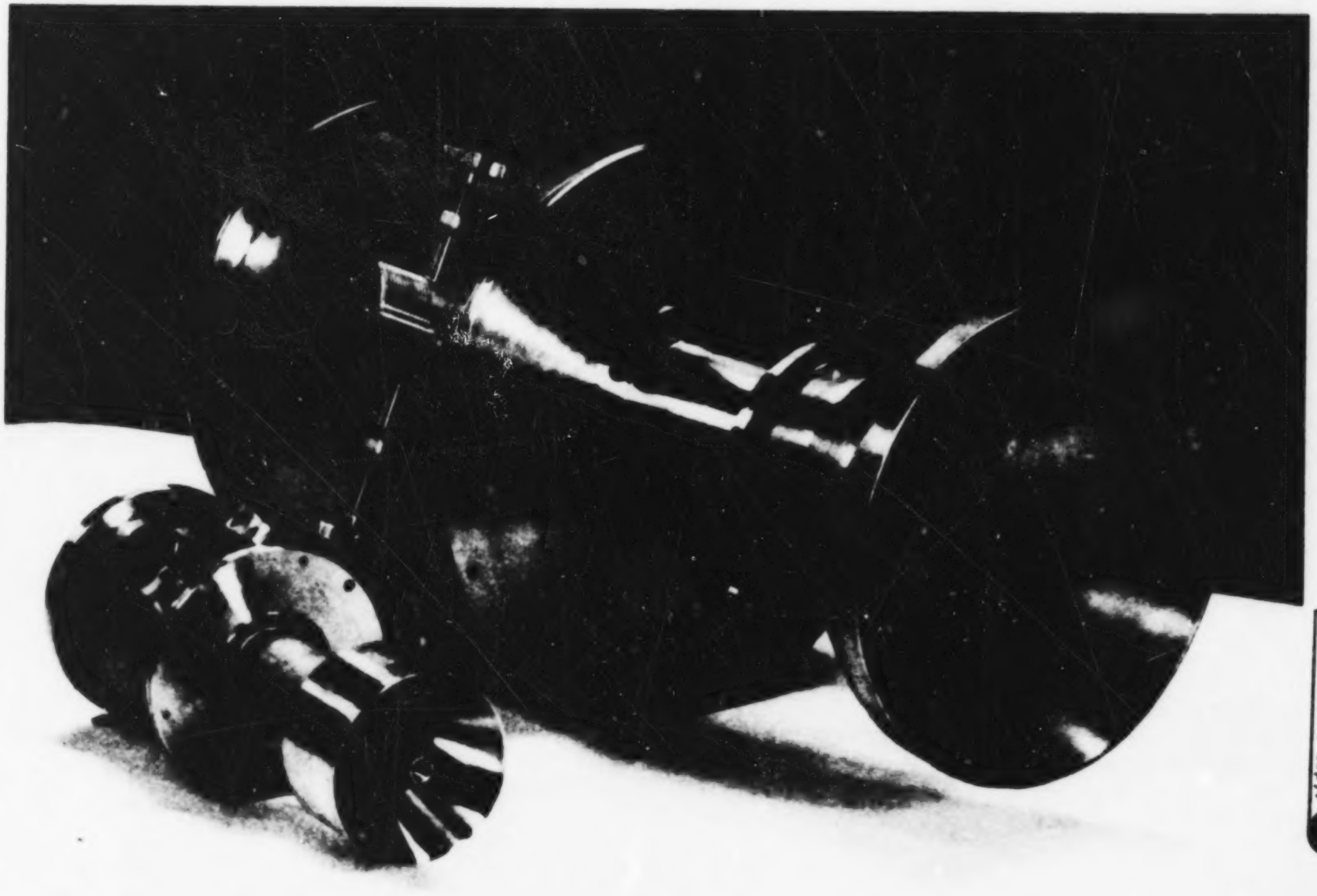


Figure 2. IFRF burners.

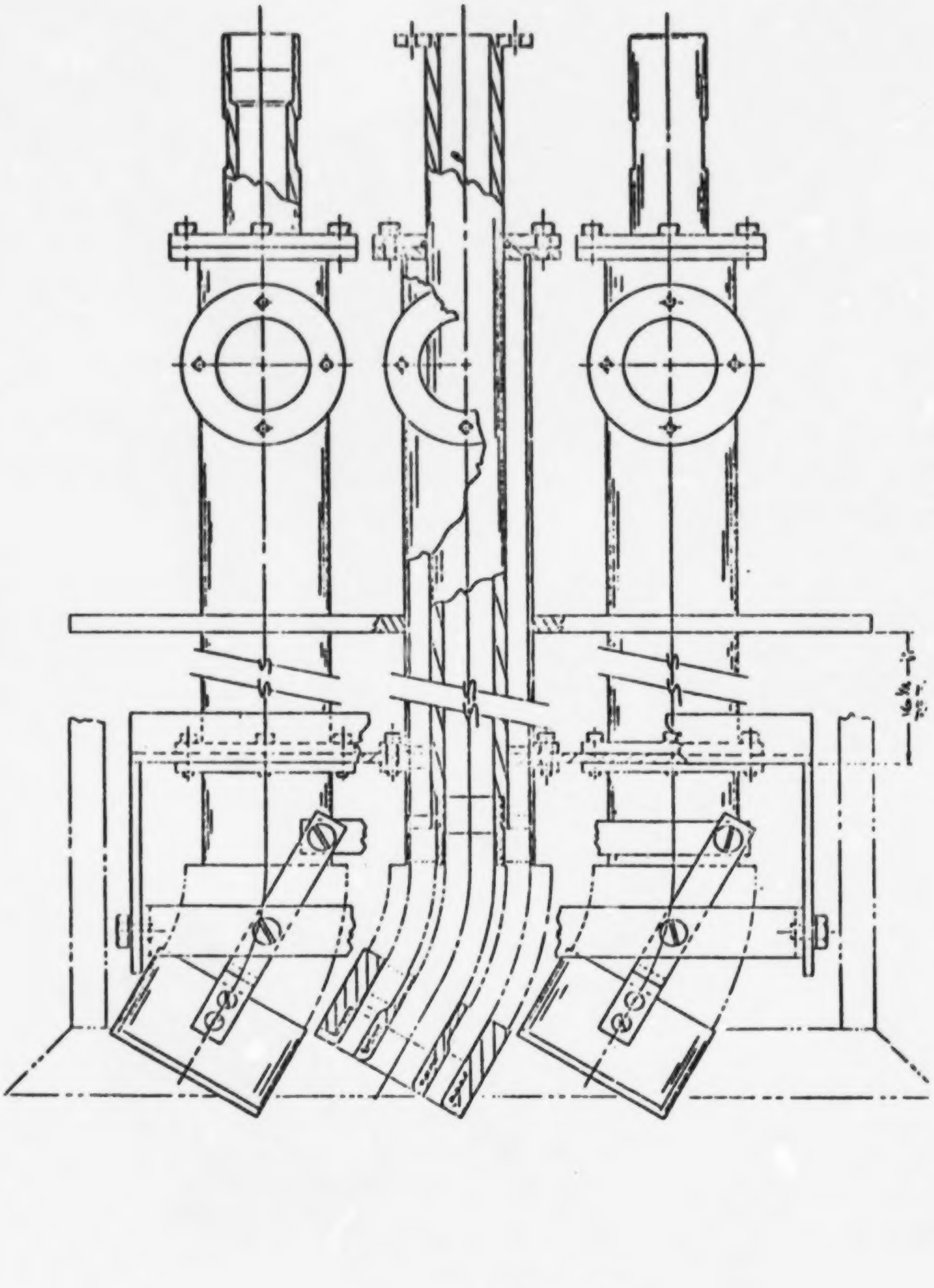


Figure 3. Corner burners.

chamber. Each exchanger consists of six drawer assemblies with twenty stainless steel u-tubes for easy removal of heat exchange surface. Refractory plugs have also been provided to fill the drawer windows when the heat exchange surface is removed.

Figure 4 shows the relationship between heat release rate per unit volume and firing rate, and indicates typical industrial design practice for heat release per unit volume. The upper boundary is determined with the full heat exchanger surface installed (or using the main firebox as the combustion volume). The lower boundary is determined by the required heat exchange surface to lower the gas temperature to 400°F. A wider performance map could be obtained if additional heat exchange surface was added in the crossover duct or if the baghouse was bypassed. Water cooling could also be used in the main heat exchangers, requiring less heat transfer surface and thus allowing longer residence times. Table 2 further illustrates the current performance of this facility by showing the bulk residence time, and heat release rates for various firing rates.

Figure 5 shows the general layout of the facility in Aerotherm's laboratory.

RESEARCH PROGRAM

The 28 month operating contract for the EPA furnace is subdivided into the following phases:

- Phase I: Installation and Shakedown (four months)

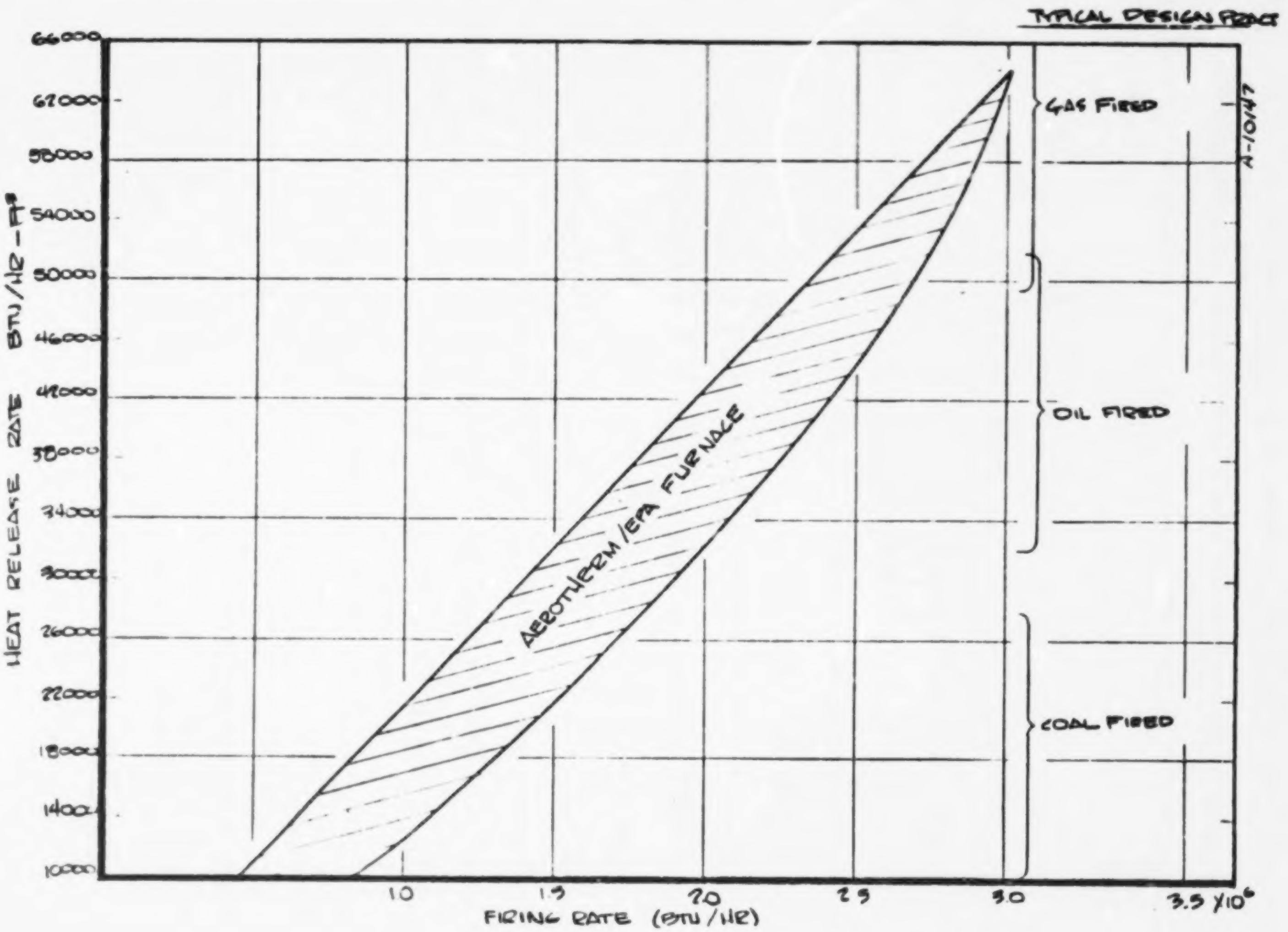


Figure 4. Furnace performance map.

TABLE 2. FURNACE PERFORMANCE PARAMETERS FOR VARIOUS CONFIGURATIONS

Configuration (Furnace plus n empty sections)	Vol ft^3	Total Heat Release (Btu/hr)					
		3 x 10^6		1.5 x 10^6		1.0 x 10^6	
		R.T.	H.R.	R.T.	H.R.	R.T.	H.R.
Furnace	46.60	0.67/0.83	64,378	1.34/1.68	32,189	2.01/2.51	21,459
Furnace + 1	57.27	☒	☒	1.65/2.06	26,191	2.47/3.09	17,461
Furnace + 2	67.93	☒	☒	1.96/2.45	22,068	2.93/3.66	14,721
Furnace + 3	78.60	☒	☒	☒	☒	3.39/4.24	12,723*

KEY:

R.T. = Residence time (sec) at 25 percent excess air/stoichiometric

H.R. = Volumetric heat release rate Btu/hr-ft^3

☒ = Insufficient heat exchange surface

* = Marginal heat exchange surface

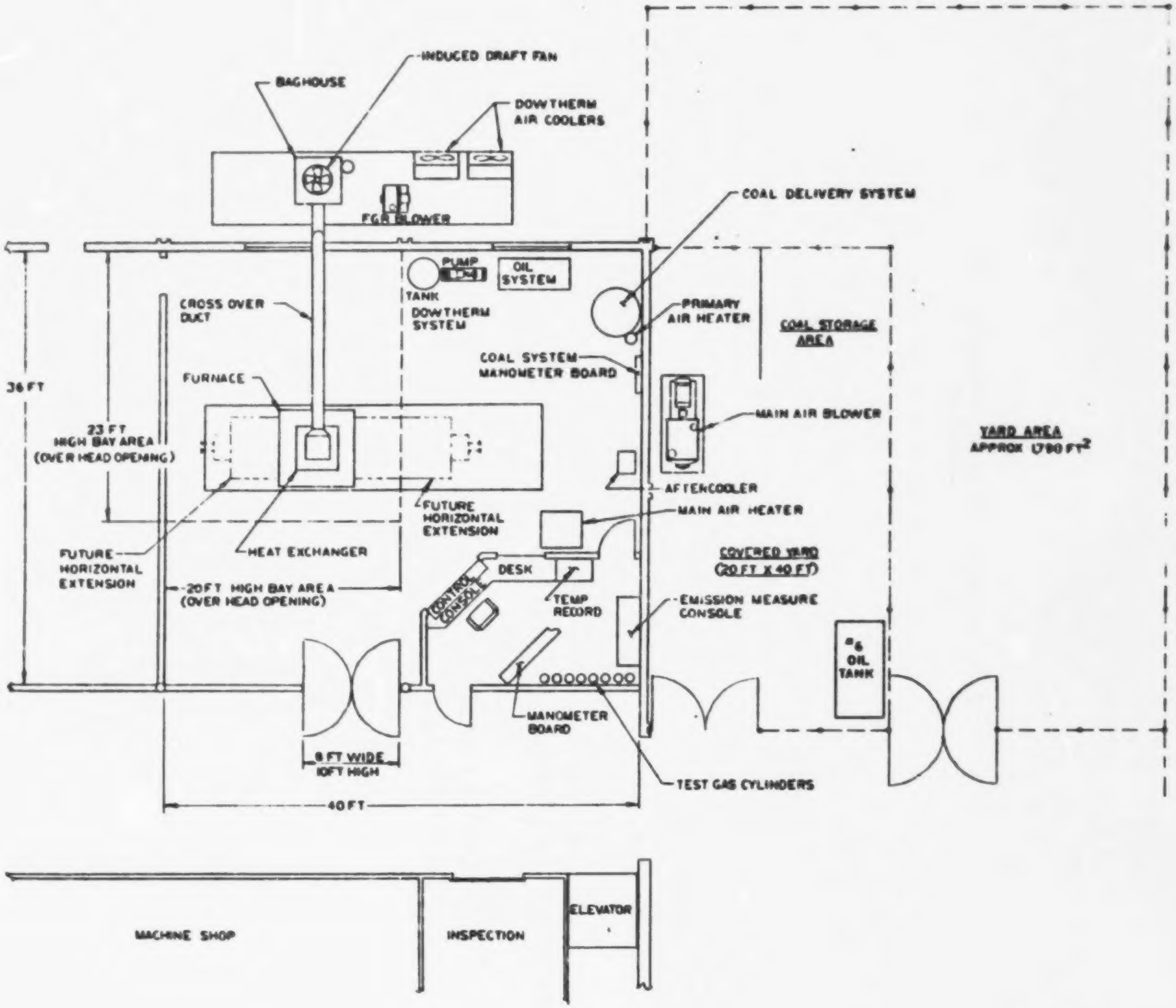

BAGHOUSE
INDUCED DRAFT FAN
DOWTHERM AIR COOLERS
FGR BLOWER
COAL DELIVERY SYSTEM
PUMP
OIL SYSTEM
TANK
DOWTHERM SYSTEM
CROSS OVER DUCT
PRIMARY AIR HEATER
COAL STORAGE AREA
COAL SYSTEM MANOMETER BOARD
36 FT
FURNACE
23 FT HIGH BAY AREA (OVER HEAD OPENING)
MAIN AIR BLOWER
YARD AREA APPROX 1780 FT²
AFTERCOOLER
FUTURE HORIZONTAL EXTENSION
MAIN AIR HEATER
FUTURE HORIZONTAL EXTENSION
HEAT EXCHANGER
DESK
COVERED YARD (20 FT X 40 FT)
20 FT HIGH BAY AREA (OVER HEAD OPENING)
CONTROL CONSOLE
TEMP RECORD
EMISSION MEASURE CONSOLE
#6 OIL TANK
MANOMETER BOARD
8 FT WIDE 10 FT HIGH
TEST GAS CYLINDERS
40 FT
MACHINE SHOP
INSPECTION
ELEVATOR

Figure 5. EPA multiburner coal furnace and support systems.

- Phase II: Conventional Fossil Fuels Test Program (12 months)
- Phase III: Mixed and Nonconventional Fuels Test Program (12 months)

The Phase I shakedown tests served to certify the system design and also yielded the operational and control characteristics needed to execute the subsequent test program.

The objective of the Phase II test program is to develop advanced techniques for the control of combustion generated air pollution for application to large and intermediate sized steam generators firing conventional fossil fuels. For this series the furnace will be run in the single wall fired mode using five 300,000 Btu/hr burners and in the corner fired mode using four or eight burner arrays. Emphasis will be on fuels with high fuel NO forming potential — coal and residual oil — with secondary emphasis on distillate oil and natural gas. Western Kentucky #9 coal and Chevron bay area residual oil (S = 1%, N = 0.8%) have been selected as the primary fuels. Two other coals, Pittsburgh #8 and Big Sky Montana, and two other residual oils will be fired periodically to generalize the results obtained with the primary fuels.

The Phase II test plan is shown schematically on Figure 6. The initial furnace characterization studies will define the system operating conditions and baseline emissions to be used to interpret the

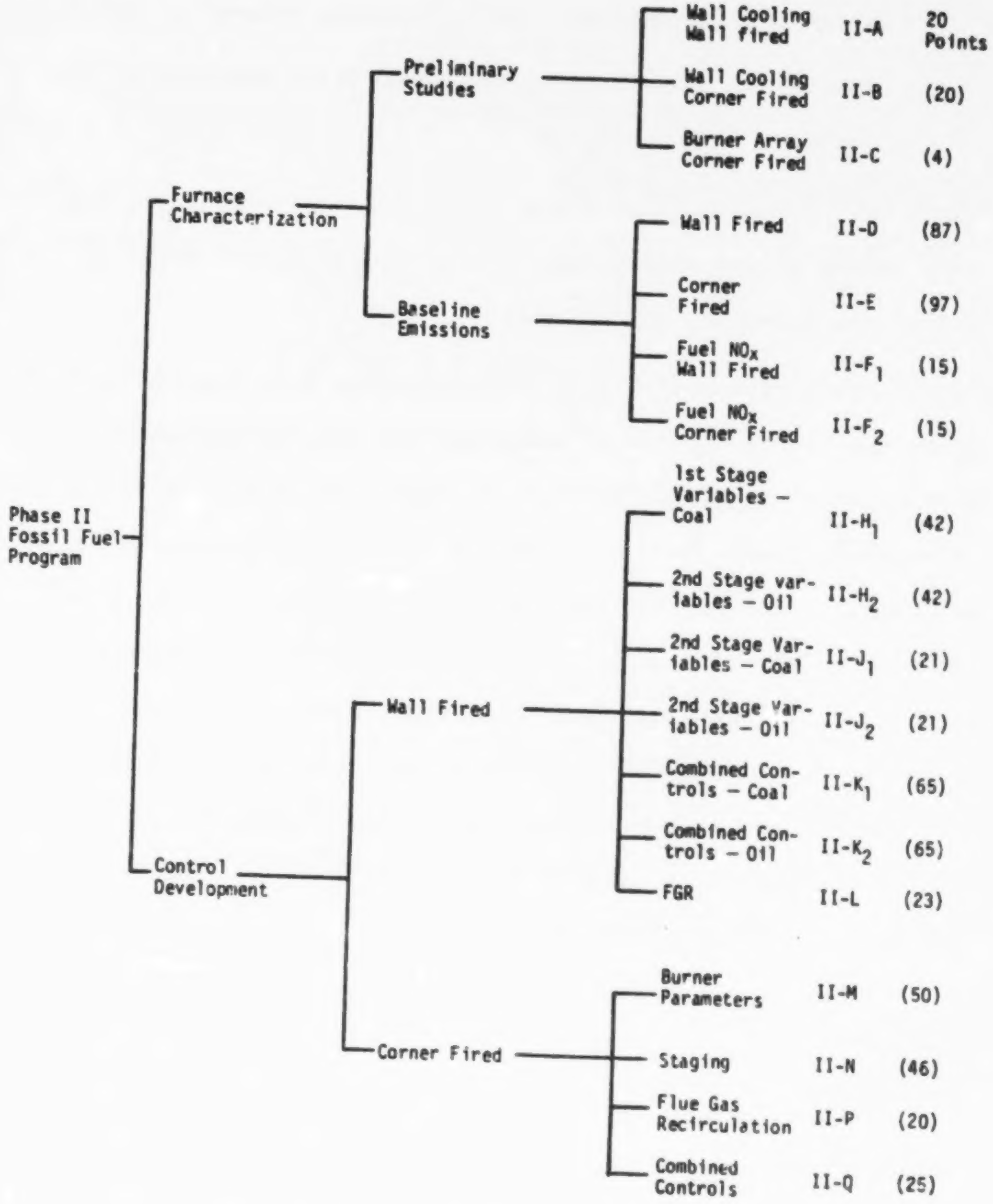

Phase II Fossil Fuel Program
Furnace Characterization
Preliminary Studies
Wall Cooling Wall fired
II-A
20 Points
Wall Cooling Corner Fired
II-B
(20)
Burner Array Corner Fired
II-C
(4)
Baseline Emissions
Wall Fired
II-D
(87)
Corner Fired
II-E
(97)
Fuel NO_x Wall Fired
II-F_1
(15)
Fuel NO_x Corner Fired
II-F_2
(15)
Control Development
Wall Fired
1st Stage Variables – Coal
II-H_1
(42)
2nd Stage variables – Oil
II-H_2
(42)
2nd Stage Variables – Coal
II-J_1
(21)
2nd Stage Variables – Oil
II-J_2
(21)
Combined Controls – Coal
II-K_1
(65)
Combined Controls – Oil
II-K_2
(65)
FGR
II-L
(23)
Corner Fired
Burner Parameters
II-M
(50)
Staging
II-N
(46)
Flue Gas Recirculation
II-P
(20)
Combined Controls
II-Q
(25)

Figure 6. Summary of Phase II test sequences.

results of the control development studies. The preliminary wall cooling studies, II-A and II-B, will indicate the level of wall cooling needed to give the best simulation of NO_x formation in large steam generators. The determining factors will be the level of NO_x as well as the trend with excess air, preheat and load for at least two levels of wall cooling. Gas and coal will be fired to encompass the range of thermal/fuel NO_x and the range of luminous versus gas radiation encountered in practical equipment. The wall cooling scheme established in II-A and II-B will be carried through all remaining test series. The third preliminary study, II-C, will determine if four or eight corner fired burners yield the best simulation of NO_x formation in full scale equipment.

The uncontrolled baseline emission series II-D and II-E will provide reference emission levels over the range of preheat, excess air, load and fuel type to be considered in the control development series. The baseline series will also give further characterization data to indicate the correspondence of this facility to full scale equipment. An additional baseline series, II-F, will be run to elucidate the thermal NO_x/fuel NO_x split as affected by fuel type, preheat and excess air. Concurrent tests at the University of Arizona in which argon is substituted for nitrogen in the combustion air will indicate the effect of flue gas recirculation on thermal NO_x and thereby show the fractional conversion of fuel nitrogen to NO_x. These results will be translated to the EPA/Aerotherm furnace run with a duplicate matrix and the same fuel to give semi-quantitative guidelines on fuel nitrogen conversion.

The control development test series will be largely devoted to determining the best procedures for NO_x control through staged combustion. The wall-fired control development series will involve a systematic screening of primary first stage variables and second stage variables followed by combined testing of the best procedures identified in the screening study. The first stage screening study will investigate the following variables:

- Primary flame zone mixing due to burner swirl
- Primary flame zone stoichiometry
- First stage flame heat removal
- Bulk residence time to the point of second stage air injection
- Burner air preheat

The NO_x control results from these tests will be interpreted through the time-temperature history of the combustion gases up to the point of second stage air injection as affected by the above variables. Since the time-temperature histories and combustion intensities in this facility are similar to full scale equipment, these results will serve to establish semi-quantitative guidelines for staging in field application.

The second stage screening study, II-J , will investigate the following variables:

- Residence time from second stage air injection to quench
- Stage air preheat
- Rate of mixing of stage air with combustion gases

These results will compliment the II-H results to indicate the best overall approach to staging which will be tested in series II-K. Throughout the staging studies, measurement will be made of combustion gas temperature, local NO_x concentration and residence time distribution by means of the suction pyrometer, hot sampling probe and helium tracer measurements respectively. These measurements will provide insight into how staging variables affect NO_x formation and control and will also allow some generalization of the results toward full-scale application guidelines.

Flue gas recirculation for NO_x control with dirty fuels, primarily residual oil, will be studied on a limited basis in series II-L. The objectives are (1) determine the effectiveness of FGR as a function of fuel type, excess air and preheat, and (2) illustrate qualitatively how fuel NO_x conversion is affected by primary system variables. These FGR tests will actually be run in advance of the staging studies. If the FGR technique shows promise, it will be included in the combined control optimization series, II-K.

The corner fired control development series will extend the staged combustion guidelines established in the wall fired series to the corner fired configuration. Additionally, the corner fired series will study the effect of burner parameters on NO_x formation and control. Series II-M provides for study of the following corner fired burner configurations:

- Burner firing orientation
- Eccentric fuel/air injection
- Biasing of burner stoichiometry between the upper and lower nozzles

These tests will identify low NO_x configurations and will indicate the effects of hardware settings on fuel/air mixing in the jets and in the central fireball. The observations on fuel/air mixing will guide the selection of burner configuration to be used in the subsequent studies on staging, FGR and combined controls.

The Phase III mixed and nonconventional fuels test program has the objective of defining practical design guidelines for emission control with the firing of nonconventional fuels. Mixed fuel firing shows promise as a new and powerful NO_x control option and so will tentatively occupy eight months of the 12 month test program with nonconventional fuels covering the remaining four months. Mixed fuels approaches considered for Phase III include:

- Blends of fuels to achieve low net fuel N
- Simultaneous firing of two fuels through two separate sets of burners to provide a shielding of the high N fuel and hence a delayed exposure of fuel N to combustion air, suspected to be an effective control technique for fuel NO_x
- Simultaneous firing of two fuels through separate elements of the same burner to provide a shielding effect on the scale of an individual burner*
- Staged fuel addition, or "reburning," to reduce NO in a secondary combustion zone

Table 3 lists the candidate fuels for both individual firing and dual fuel firing, and briefly indicates the selection rationale in each case. The individual tests are limited to important potential boiler fuels: oil shale product, solvent refined coal, coal char, and one high nitrogen waste fuel. The particular selections are influenced by the prototype characters of these fuels as being representative of general classes of new fuels and as having interesting NO_x control difficulties. The only conspicuous absence from this single-fuel-firing list are synthetic fuel gases produced from coal.

---

*For wall firing, other EPA programs currently are developing this technology. Consequently, the stress here will be on tangential firing.

TABLE 3. CANDIDATE FUELS FOR PHASE III AND DIGEST OF SELECTION RATIONALE

Mode	Category	Fuel	Rationale
Single Fuel Firing	New Candidate	Shale Oil	Possibly important new fuel; high fuel nitrogen; get baseline data for dual fuel tests
		Solvent Refined Coal	Ditto; plus unusual combustion properties
	Waste	Coal Char	Interesting waste; difficult burning problems
		Gas waste with NH_3, or waste liquid hydrocarbon	Common waste; fuel nitrogen problem
Dual Fuel Firing	Conventional	Coal	Major fuel type
		Residual Oil	Major fuel type
		Distillate Oil	Major fuel type
		Natural Gas	Major fuel
	New Candidate	Low Btu Gas	Special combustion properties; important candidate
		Shale Oil	Fuel nitrogen problems; important candidate
		Solvent Refined Coal	Fuel nitrogen problems; important candidate
		Hydrogen	Good reburning candidate in fuel mixes
		Ammonia	Good reburning candidate in fuel mixes
	Wastes	Coal Char	Interesting waste, difficult burning problem
		Sewage Sludge	Ditto
		Gaseous Waste with NH_3	Common waste; fuel nitrogen problem
		Chlorinated H-C	Common waste

To the rather minor extent that these fuels are candidates for single fuel firing in boilers, other EPA programs are currently covering the development of control technology. These gases are included in the dual-fuel test sequence, where they are potentially very important for NO_x and SO_x control.

The dual fuel test plan includes many fuel combinations. Most of these represent a high nitrogen ("dirty") fuel fired with a small amount of low nitrogen ("clean") fuel to explore shielding or reburning effects. Table 4 gives a partial overview. It does not show the blended fuel combinations.

The Phase III test sequences have been divided into four elements for planning purposes:

- Mixed conventional fuels (4 months)
- New candidate fuels (2 months)
- Mixed conventional/new candidate fuels (4 months)
- Waste fuels and mixed waste/other fuels (2 months)

The resulting program represents the first wide scope exploration of:

- The special control problems of a number of new candidate fuels and waste fuels
- Highly promising dual-fuel emissions control techniques

and exploits fully the flexible design features of the multiburner facility.

TABLE 4. IMPORTANT DUAL FUEL COMBINATIONS FOR PHASE III TESTING

		Dirty Fuel			
		Coal	Resid	Shale Oil	Coal Char
Clean Fuel	Gas	X	X		X
	Low Btu Gas	X	X		X
	Dist	X	X	X	
	Hydrogen	X	X		

ACKNOWLEDGEMENTS

The contributions of D. W. Pershing and Professor J. O. L. Wendt, of the University of Arizona, to the formulation of the test plan is gratefully acknowledged.

TABLE OF CONVERSION FACTORS FOR SI UNITS

Equivilant SI Units	English Units
0.0254m	inch
0.3048m	Ft
$0.028317 m^3$	Ft^3
0.45359Kg	lb
$6895\ N/m^2$	Psi
$0.003785\ m^3$	Gallons
1055.06	Btu
$37{,}259\ J/m^3$	Btu/Ft^3
$(T_f-32)\ /1.8°C$	°F

2:25 p.m.
Pilot Scale Investigation of Combustion Modification Techniques for NO_x Control in Industrial and Utility Boilers
Richard E. Brown, Aerotherm Acurex

Q: In noticing most of the presentations of yesterday and today, the effect of wall temperatures on NO_x emissions just seems to be one of the most pronounced effects. Now I noticed how with your U-tubes you can affect a cooling rate of the flue gases, but they are not down in the furnace. By the time the gases are going up through those cooling tubes there is going to be no back mixing into the flame zone. Maybe I am wrong, but I see that this furnace is compared to what everyone else seems to see as the most important parameter, that's wall temperature -- and I don't see how we can work that into...

A: We will be putting cooling walls in this furnace, and vary the spacings to look at various cooling wall patterns. That is part of our base line test series.

Q: Will you be testing two-stage combustion on a single burner setup?

A: Perhaps. Burner configuration will be determined during our baseline series and we think it will probably be the five burner array. Most likely we will not look at stagedcombustion for the single burner until we go to some horizontal extensions. This furnace is also designed such that we can go to horizontal extensions, either end. And in that case we may look at two-staged combustion with the single burner.

Q: The word "shielding," could you interpret that please?

A: The effect of introducing fuel and air in either a fuel-rich or fuel-lean mode, and providing another fuel to shield the main fuel, say, from the oxygen.

* * *

Q: What method are you going to use to preheat your air?

A: We are preheating the air with electrical heaters up to 800° F.

Q: And on the flue gas recirculation, are you taking it directly from the stack?

A: We are taking it downstream of the baghouse; we are taking the particulate and the fly-ash out.

Q: And where are you reinjecting it?

A: We will reinject it at this time into the secondary air streams, although we have the ability to inject it at any location.

SESSION III

PROCESS RESEARCH AND DEVELOPMENT

D. G. Lachapelle, Chairman

OVERFIRE AIR AS A NO_x CONTROL TECHNIQUE FOR TANGENTIAL COAL-FIRED BOILERS

By:

A. P. Selker

Combustion Engineering, Inc.

Windsor, Connecticut

Preceding page blank

OVERFIRE AIR AS A NO_x CONTROL TECHNIQUE FOR TANGENTIAL COAL-FIRED BOILERS

A. P. Selker
Combustion Engineering, Inc.
Windsor, Connecticut

INTRODUCTION

The purpose of this EPA sponsored program was to determine the effectiveness of overfire air (OFA) and biased firing* as methods for NO_x control on tangentially coal fired utility boilers. In addition, the effects of these emission control techniques on overall unit performance were evaluated. The program was divided into two contract phases:

Phase I (EPA Contract 68-02-0264) consisted of selecting a suitable utility boiler to be modified for the incorporation of an overfire air system and conducting studies in preparation for the actual unit modifications and test program. This phase was completed in 1973.

Phase II (EPA Contract 68-02-1367) consisted of modifying and testing the utility boiler selected in Phase I to evaluate overfire air and biased firing as methods for NO_x control. This phase also included the completion of detailed fabrication and erection drawings, installation of analytical test equipment, updating of the preliminary test program, and analysis and reporting of test results.

This program was conducted with the cooperation and active participation of Alabama Power Company at their Barry Steam Station Unit 2. This unit is a natural circulation, balanced draft utility plant boiler firing coal through four elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 408,000 kg/hr main steam flow with a superheater outlet temperature and pressure of 538 C and 131.8 kg/cm^2. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating. A side elevation of the unit prior to modification is shown in Fig. 1.

OVERFIRE AIR SYSTEM DESIGN

The overfire air system (Fig. 2) incorporated in the unit provided for introducing a maximum of 20% of the total combustion air above the fuel admission nozzles at full unit loading. The overfire air was introduced into the furnace tangentially through two separate

---

*Biased firing consists of removing individual fuel elevations from service while maintaining full airflow through these same elevations.

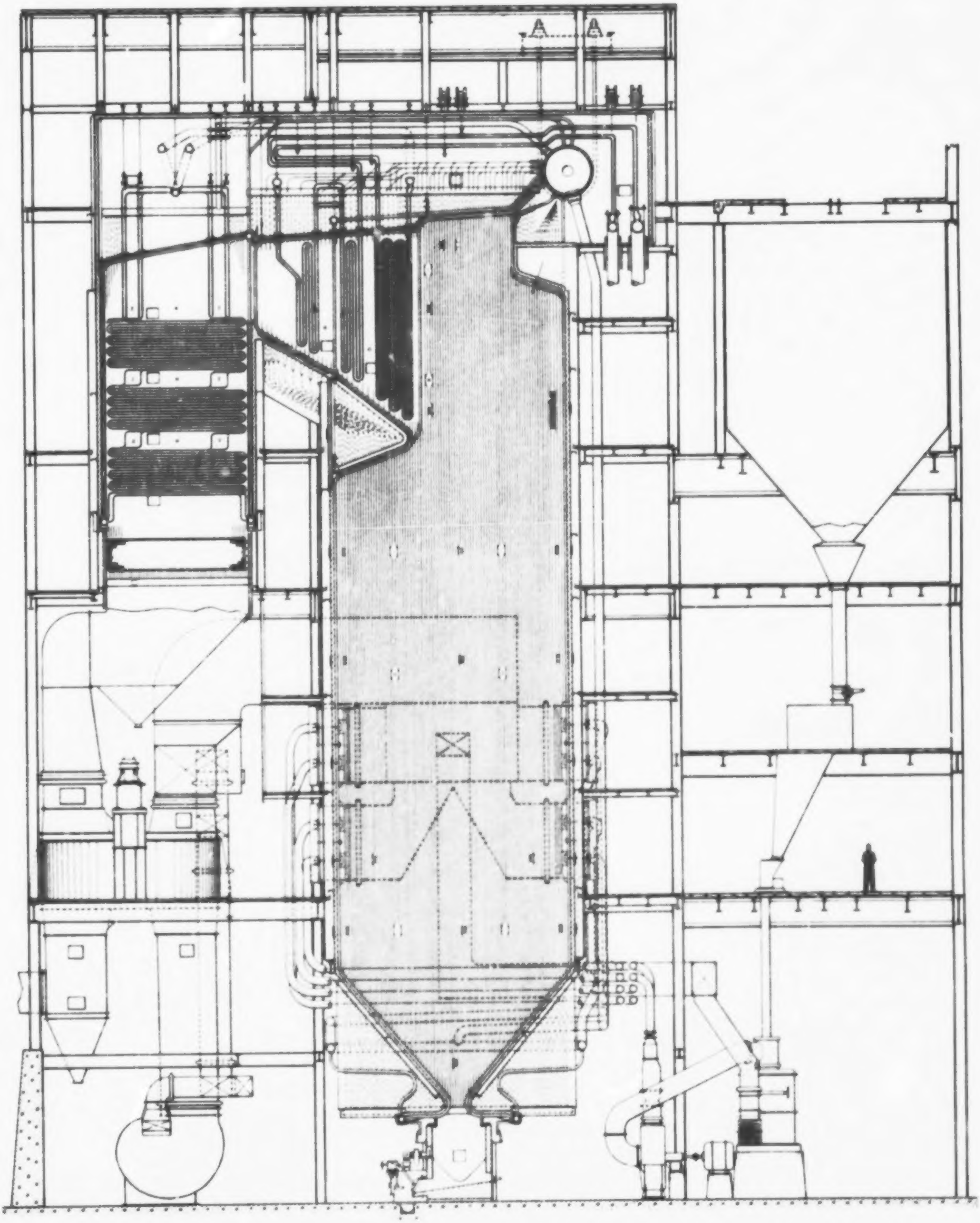


Fig. 1: Test unit side elevation, Alabama Power Company, Barry 2

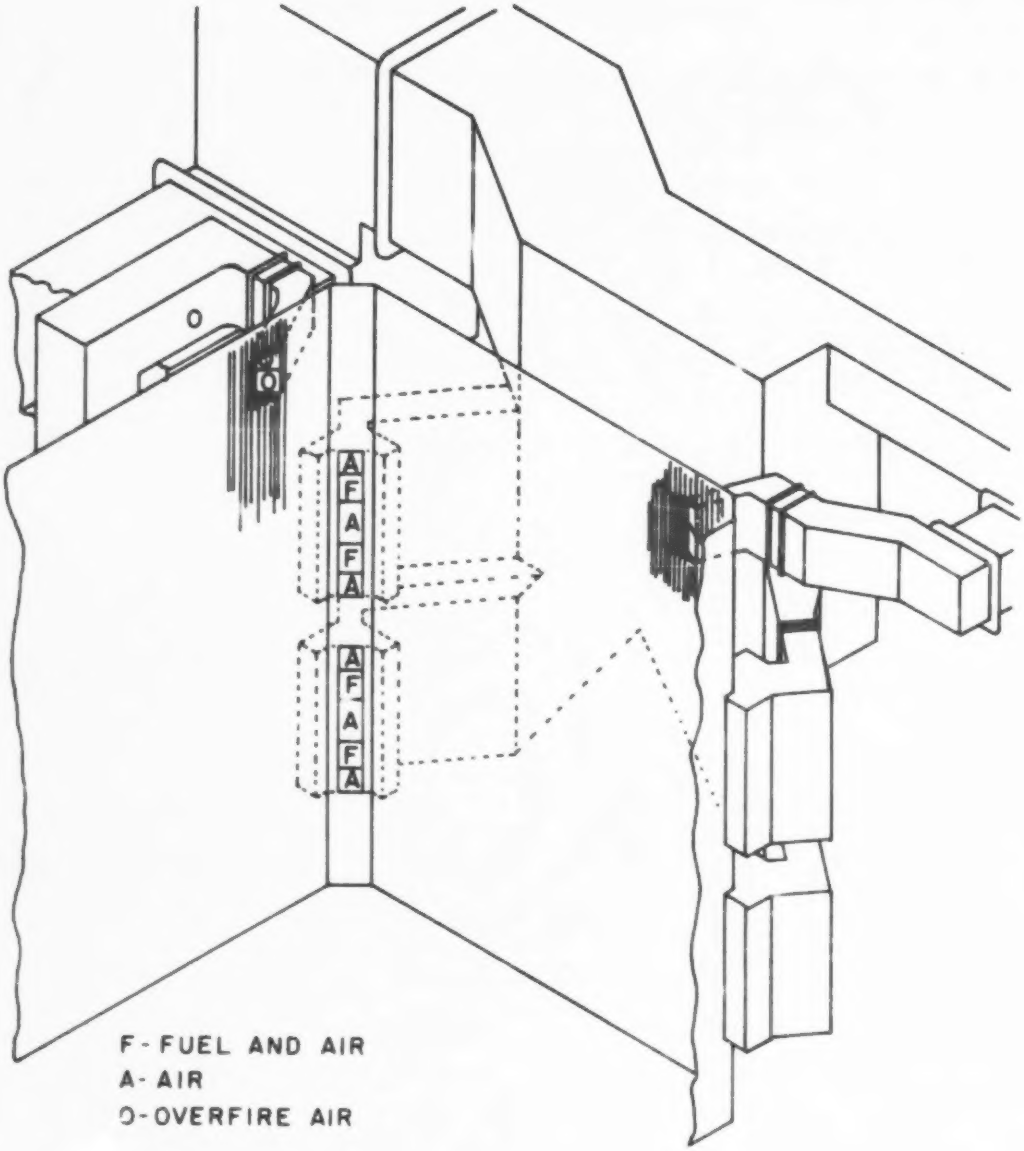


Fig. 2: Test unit overfire air system schematic

compartments near each furnace corner located approximately 2.4 meters above the fuel admission zone. While on new unit designs the overfire air ports (Fig. 3) are designed as vertical extensions of the corner windboxes, on the field modified unit, separate compartments were required due to structural considertions. The system provided for air nozzle tilting (±30 deg. from vertical plane) and separate compartment flow control dampers to permit studying the effects of various airflow rates, introduction angles, and compartment airflow distributions.

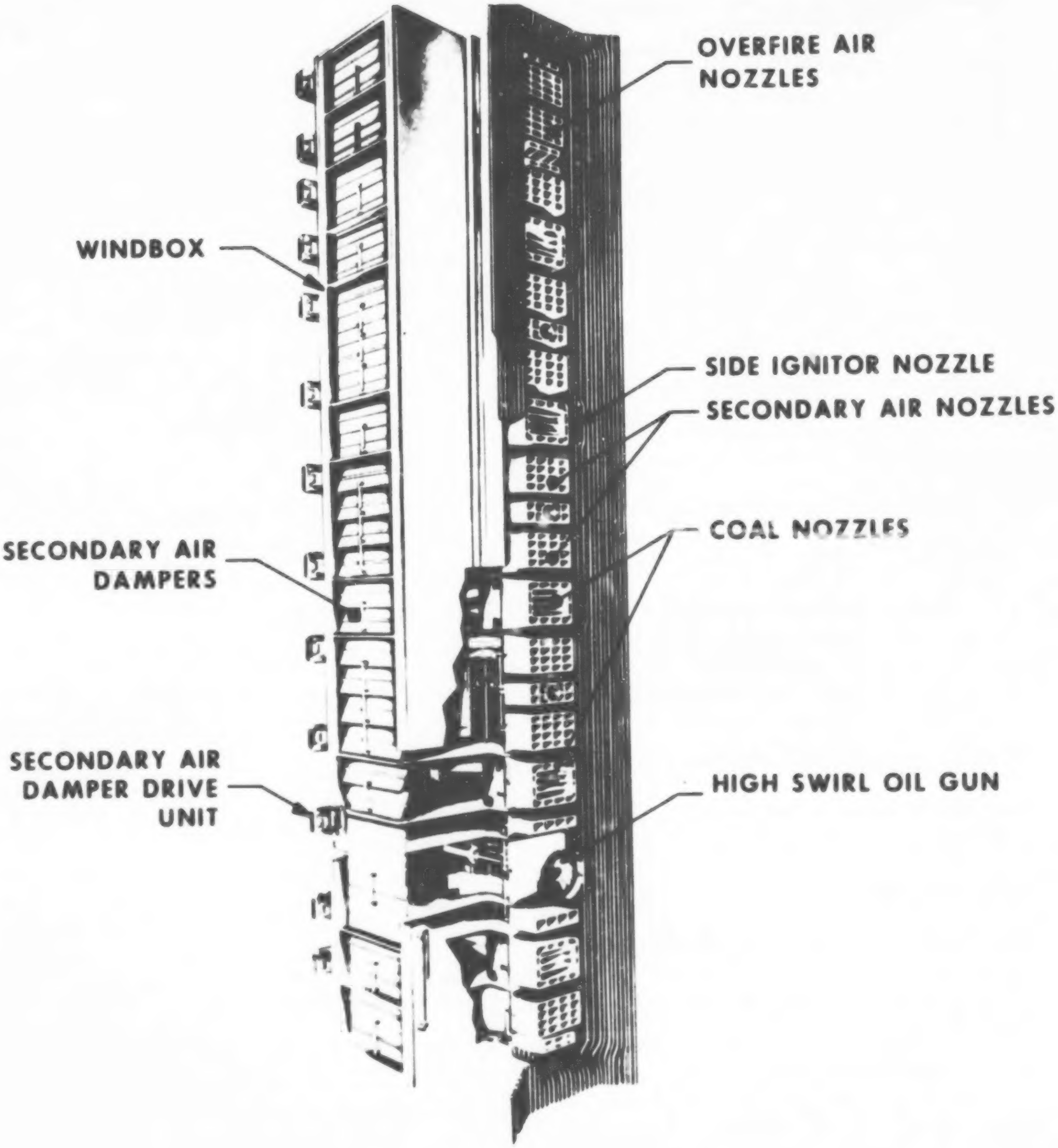
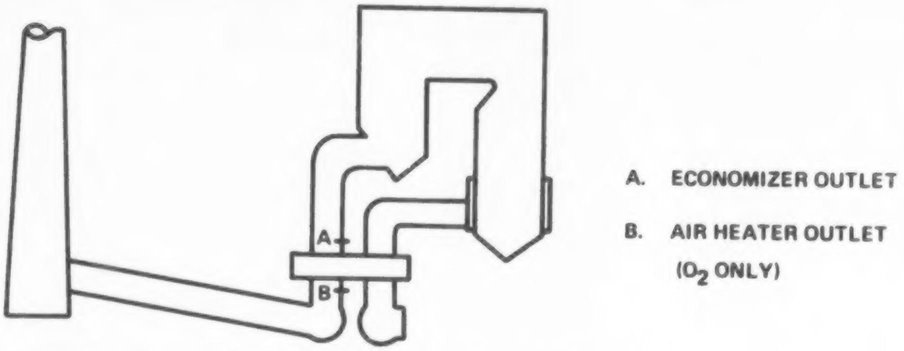

OVERFIRE AIR NOZZLES
WINDBOX
SIDE IGNITOR NOZZLE
SECONDARY AIR NOZZLES
COAL NOZZLES
SECONDARY AIR DAMPERS
SECONDARY AIR DAMPER DRIVE UNIT
HIGH SWIRL OIL GUN

Fig. 3: Corner windbox showing overfire air system

TEST INSTRUMENTATION

In order to evaluate the effect of using overfire air as a combustion process modification technique for emissions control, a grid of stainless steel flue gas sample probes was installed on the unit's economizer and air preheater outlets as shown in Fig. 4.



STAINLESS STEEL FLUE GAS SAMPLE PROBE LOCATIONS

Fig. 4: Schematic showing location of sample probes

The gas sample from the economizer outlet was blended, transported, and preconditioned prior to analysis by the following instrumentation (Fig. 5).

1. A Scott chemiluminescence NO-NO_x analyzer (0-2000 PPM)
2. An L&N paramagnetic O_2 analyzer (0-25% O_2)
3. Beckman non-dispersive infrared CO analyzer (0-1000 PPM)
4. A Scott flame ionization Total Hydrocarbon (THC) Analyzer (0-100 PPM)

A schematic of the gas analysis system is shown in Fig. 6.

Unit performance was monitored using the instruments and analytical procedures shown in Table I.

TEST PROGRAM

The Phase II test program called for the evaluation of overfire air as an emissions control system. Also evaluated were existing process variables, including excess air, unit loading, and air/fuel distribution.

To properly assess the effect of the overfire air modifications on unit performance and emission levels, the test program was divided into two distinct phases.

1. The first phase, run prior to modification, consisted of baseline

TABLE I

INSTRUMENTS AND ANALYTICAL PROCEDURES FOR MONITORING UNIT PERFORMANCE

PARAMETER		INSTRUMENT/ANALYTICAL PROCEDURE
Flow rates	Steam and Water	
	Feedwater flow	Flow orifice
	Reheat and superheat desuperheat spray	Heat balance (deg. F & PSIG) around desuperheater
	Reheat flow	Heat balance around reheat extraction and estimated turbine gland seal losses
	Air and Gas	
	Total Air and Gas Weight	Calculated
	Overfire air	Pitot traverse
	Air heater leakage	Paramagnetic O_2 analyzer
Temperatures	Steam and Water Deg. F	
	Unit absorption rates	Calibrated stainless steel sheathed CR-C well & button TC's
	Waterwall absorption	Calibrated stainless steel sheathed CR-C chordal WW TC's
	Air and Gas Deg. F	CR-C TC's Water cooled probes Pt/Pt-10% Rh TC's
Pressures	Steam and Water PSIG	
	Unit absorption rates	Pressure gauges and/or transducers
	Unit draft loss	Water manometers
	Temperature and Pressure	C-E data logger capacity: 400 temperatures, 50 pressures
Laboratory analysis	Fuel and Ash	ASTM procedures

Reproduced from
best available copy.

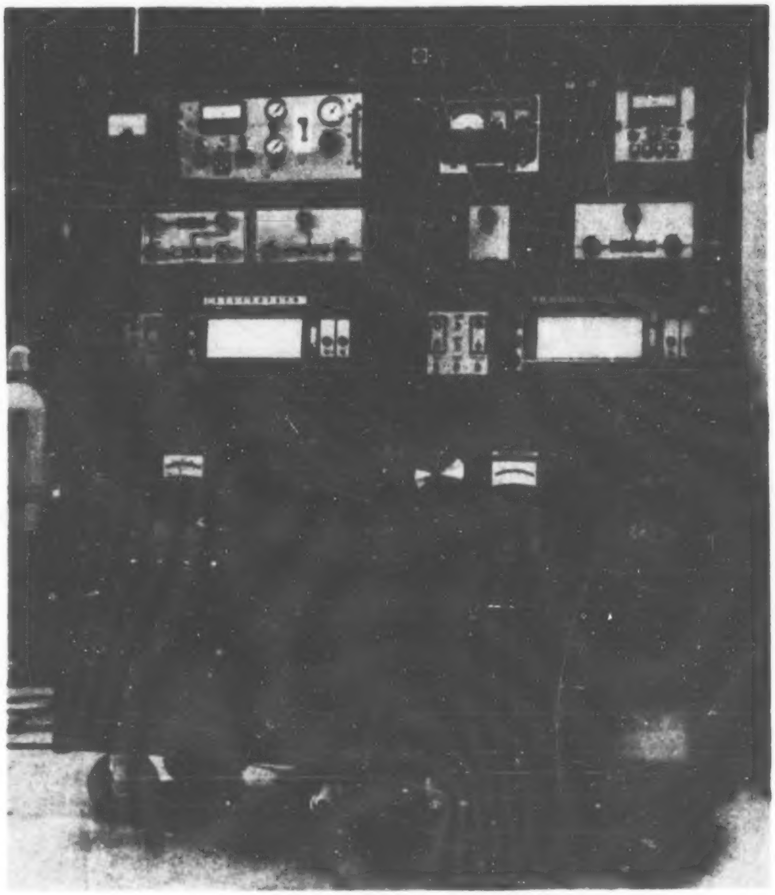


Fig. 5: Gaseous emissions test system

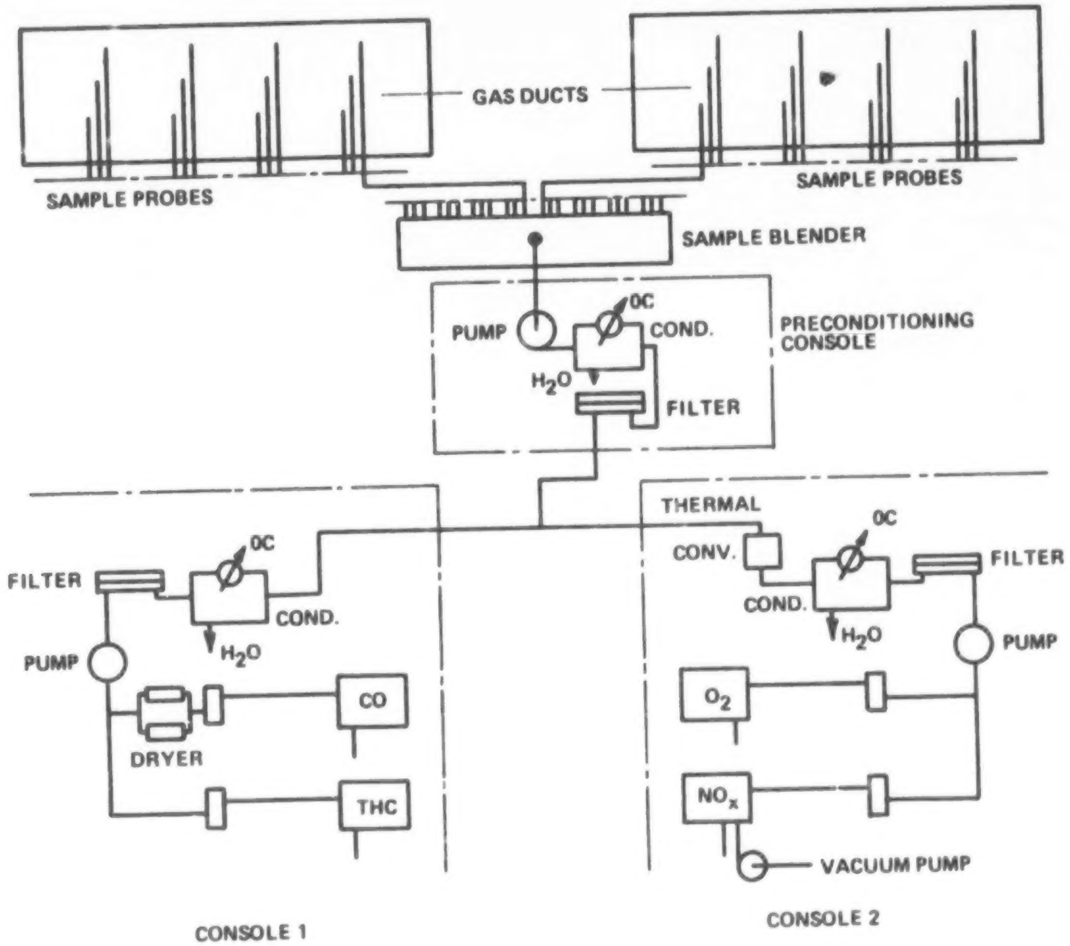

GAS DUCTS
SAMPLE PROBES
SAMPLE PROBES
SAMPLE BLENDER
PUMP
0C
COND.
H_2O
FILTER
PRECONDITIONING CONSOLE
FILTER
0C
COND.
H_2O
PUMP
DRYER
CO
THC
THERMAL
CONV.
0C
COND.
H_2O
FILTER
PUMP
O_2
NO_x
VACUUM PUMP
CONSOLE 1
CONSOLE 2

Fig. 6: Gas analysis system

and biased firing programs as well as 30-day waterwall corrosion coupon studies at baseline and optimum biased firing conditions.

2. The second phase, conducted after unit modification, consisted of repeating the baseline evaluation (to determine if the modification had influenced unit performance) and testing the overfire air system. A 30-day waterwall corrosion coupon evaluation was also conducted at the optimum overfire air condition.

The originally planned evaluation of optimum operations with alternate coal types could not be performed due to difficulties in obtaining the necessary coal supplies. However, this information has been reported by others as a result of tests on another unit at the same station.(1)

RESULTS

The first phase of the test program characterized the baseline emission levels and unit thermal performance including the effects of various operating variables including unit load, excess air level, and furnace wall deposit variation. In addition, tests were conducted to evaluate the effect of biased firing on NO_x emissions.

Load and Excess Air Variation

Figure 7 shows that the NO_x emission levels increased with increased excess air but did not change significantly with changes in unit loading.

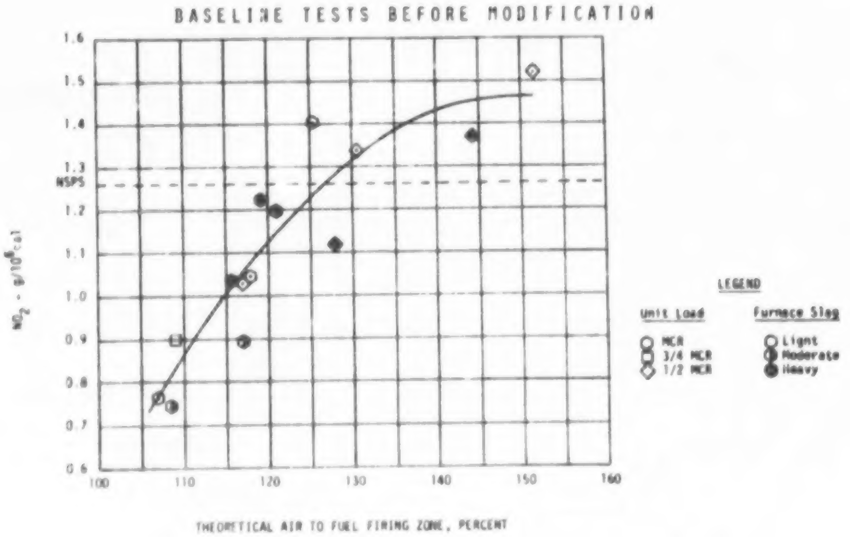


Fig. 7: NO_2 vs theoretical air to fuel furing zone -- baseline study

An average increase of 0.017 g/10^6 cal NO_2 was noted for each 1% change in unit excess air. Acceptable CO limits of 0.05 g/10^6 cal establishes minimum excess air levels of 20 to 25% (Fig. 8). (Throughout this report, NO_x emission levels are expressed as g/10^6 cal NO_2.)

On these plots, excess air (EA) is expressed as percent theoretical air (TA) to the fuel firing zone which, for unit operation without

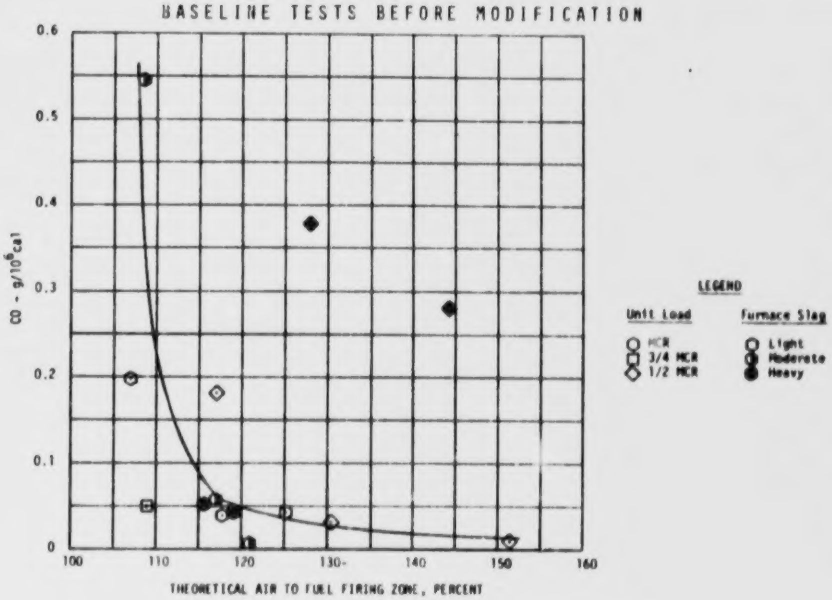


Fig. 8: CO vs theoretical air to fuel firing zone -- baseline study

overfire air, can be considered to be directly comparable (20% Total EA = 120% TA).

The excess air and load variation tests were conducted at what were considered to be clean furnace conditions to establish a baseline for wall deposit variation tests. Furnace wall deposit variations were determined by visual observations by C-E test personnel.

Furnace Wall Deposit Variation

Changes in furnace slagging did not exhibit a discernable effect on NO_x or CO emission levels (Figs. 7 and 8) with the exception of two half-load tests when higher CO levels were obtained at slagged as compared to clean furnace conditions. The reasons for this condition are not completely clear and the higher CO levels were not observed under full load heavy slag operation.

Maximum slagging conditions were obtained by operating the test unit in excess of 24-hour periods without operating any wall blowers. In this manner, slag deposits up to 4-inches thick could be obtained in and above the firing zone. Wall deposit variations were again determined by visual observation.

The slagging conditions indicated should not be considered representative of normal operation at the various excess air and unit load levels studied, but were specifically controlled for test purposes by varying soot blower operation.

Biased Firing Variation

Figure 9 shows the results of removing individual fuel elevations from service and operating them on an air-only basis. Maximum NO_x control was obtained with top elevation of fuel nozzles out of service at max-

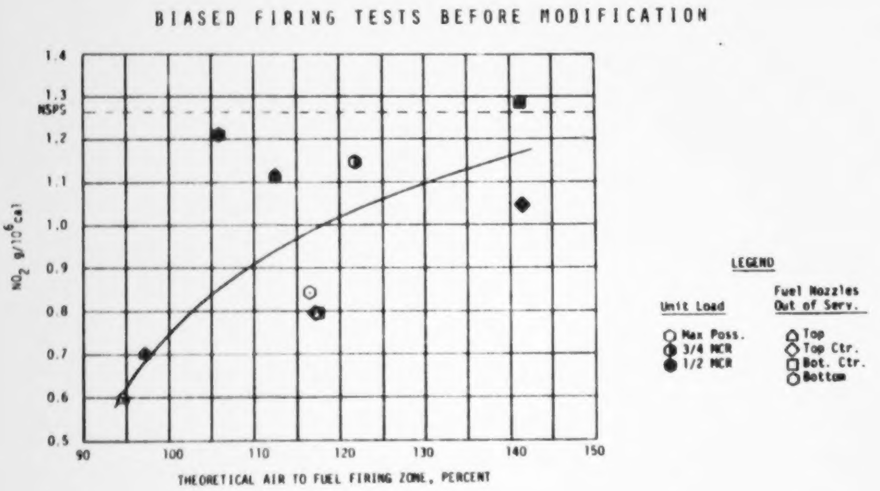


Fig. 9: NO_2 vs theoretical air to fuel firing zone -- biased firing study

imum and 75% maximum loading.

At 50% percent maximum loading, the high excess air levels required to maintain unit steam temperatures appeared to negate any NO_x reductions obtained by biasing the top fuel nozzle elevation; however, the emissions level obtained was below the current EPA limit (NSPS*) for coal fired units of 1.26 g/10^6 cal.

It should be noted that when any of the lower three fuel elevations were biased (out of service), the air introduced through the inactive fuel compartment was included in the percent TA to the fuel firing zone.

---

*New Source Performance Standard

As can be seen from Fig. 9 biasing any of the bottom three fuel elevations did not have a discernable effect on NO_x emission levels, although the emission level tended to be higher at reduced unit loadings for given percent TA levels.

Figure 10 indicates that with biased firing, low percent TA levels to the fuel firing zone were obtained without increasing CO emission levels. This condition is due to the ability to maintain acceptable

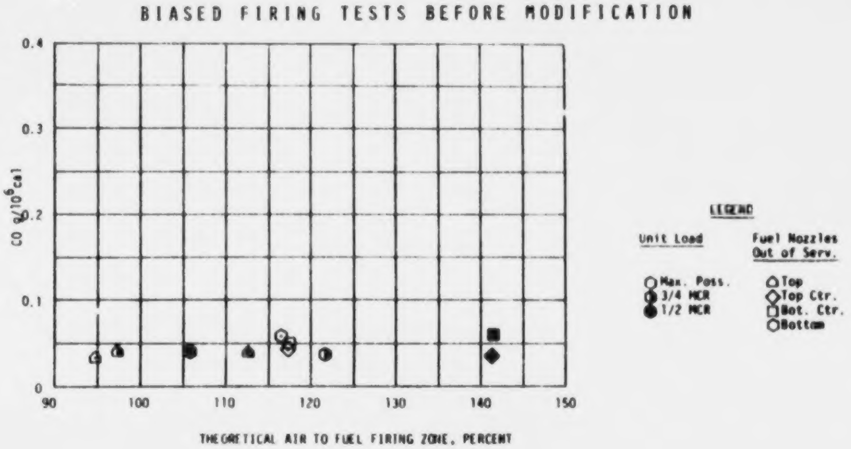


Fig. 10: CO vs theoretical air to fuel firing zone -- biased firing study

total unit excess air levels as measured at the economizer outlet during biased firing operation.

The second phase of the test program was conducted to determine baseline operating characteristics of the modified unit and to compare these to the unmodified unit test results. The overfire air system optimization program then investigated the effects of varying overfire air locations, tilt angles, and introduction rates with respect to emission levels and unit thermal performance.

Load and Excess Air, and Furnace Wall Deposit Variation (After Modification)

The baseline test program conducted prior to unit modification was repeated after installation of the overfire air system with similar results with respect to NO_x and CO emission levels being obtained as shown in Figs. 11 and 12. The NO_x levels after modification

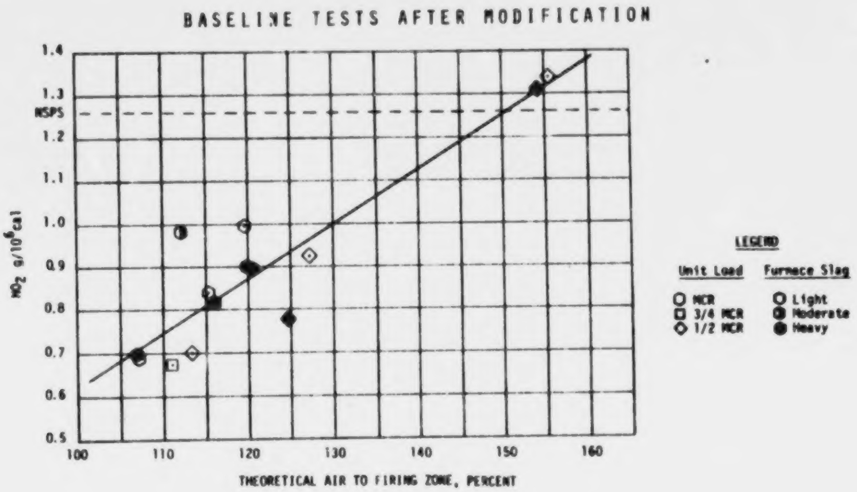


Fig. 11: NO_2 vs theoretical air to firing zone, overfire air study, load and excess air variation -- modified boiler

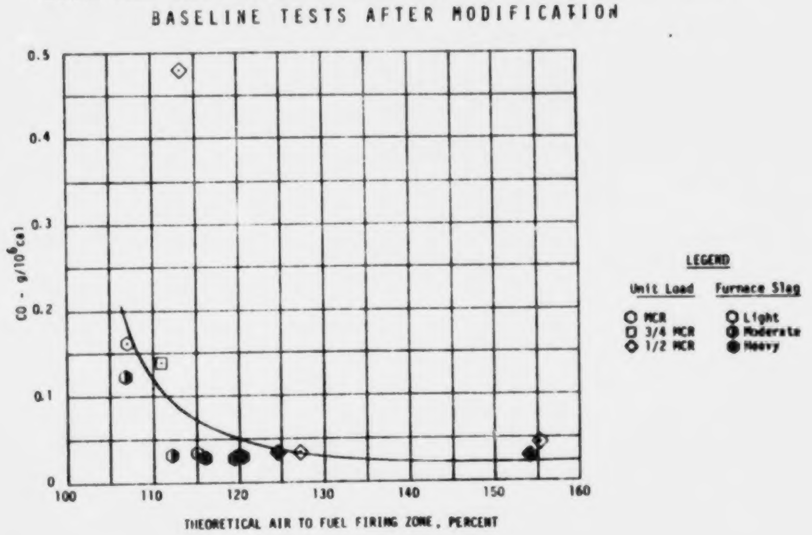


Fig. 12: CO vs theoretical air to firing zone, overfire air study, load and excess air variation -- modified boiler

tended to be slightly lower than pre-modification results; however, this could have resulted from updating of the firing system (replacement of fuel/air nozzles, etc.) during modification and a slight reduction in fuel N_2 levels and higher heating values. Again, no discernable effect on NO_x emission levels are noted due to furnace wall cleanliness.

Overfire Air (OFA) Variation

As shown in Fig. 13, the effect on NO_x levels of varying the OFA admission points was investigated with the result that NO_x levels decreased with decreasing percent TA to the fuel firing zone.

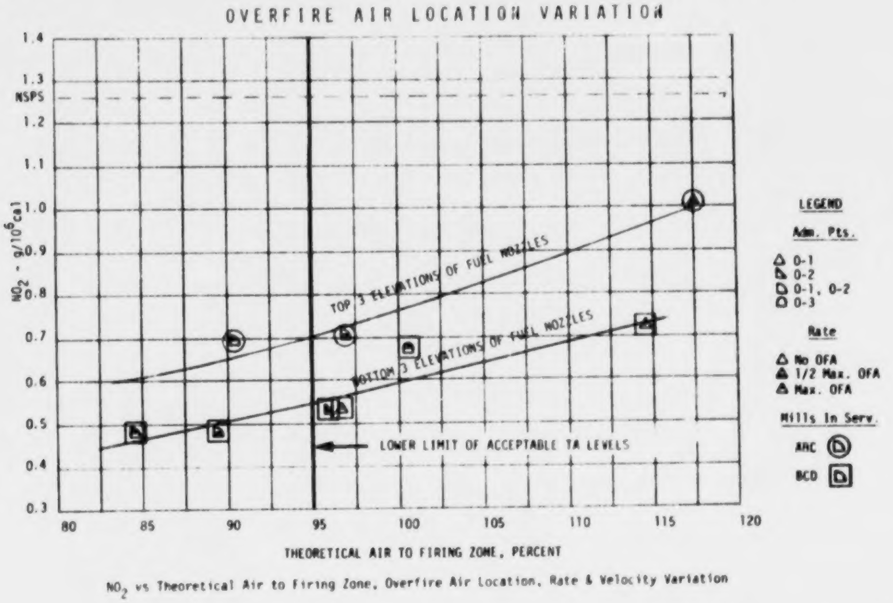


Fig. 13: NO_2 vs theoretical air to firing zone, overfire air location, rate and velocity variation

The importance of using firing zone percent TA levels now becomes apparent as this procedure provides a mechanism for correlating test results while total excess air levels as measured at the economizer outlet provide no meaningful base for data correlation.

NO_x levels were found to be generally higher with the top 3 elevations of fuel nozzles in service than with the bottom three elevations. We think this is due to the increased distance between the fuel firing zone and the admission point for the OFA.

Operation at TA levels below 95% did not result in significant reduction in NO_x emission levels. As shown in Fig. 14, CO levels remained acceptable for the duration of the test series. Total excess air as measured at the economizer outlet was maintained at approximately 27 percent.

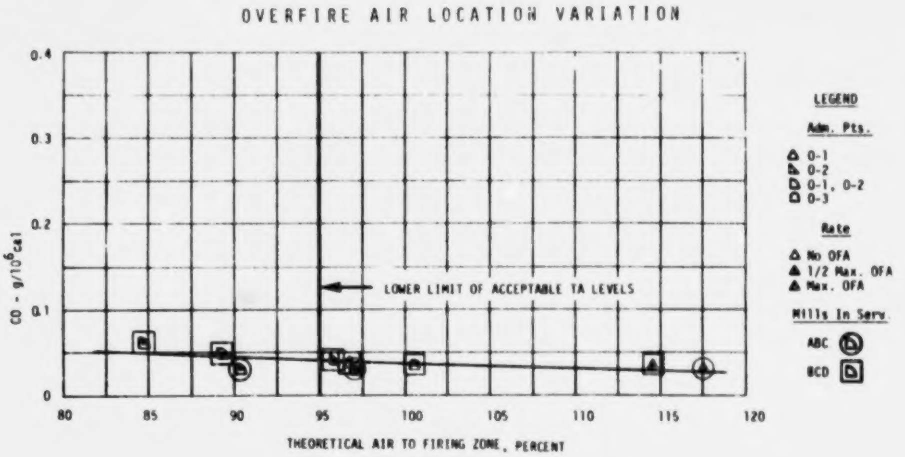


Fig. 14: CO vs theoretical air to firing zone, overfire air location, rate and velocity variation

Overfire Air Tilt Variation

A test series was conducted at full unit loading to determine the effect of varying OFA and fuel nozzle tilts on NO_x and CO emission levels. These tests were conducted with total excess air and TA levels to the firing zone of 24 and 92 percent, respectively, and moderate waterwall slagging conditions.

Essentially, varying fuel/air and OFA nozzle tilts moved the firing zone both in the furnace and relative to the overfire air. Fuel nozzle tilts that are maximum minus combined with OFA tilts of maximum plus increased the distance between the overfire air and the firing zone. As with previous methods of increasing this distance, the NO_x emission levels were decreased. Figure 15 shows that as the tilts were moved toward one another (fuel nozzle tilts up, OFA tilts down), the OFA/firing zone separation was decreased and the NO_x levels were increased.

When the OFA tilts were maximum minus and the fuel nozzle tilts maximum plus, the term overfire air became ambiguous and the actual overfire air was less than the calculated value, as the air was being

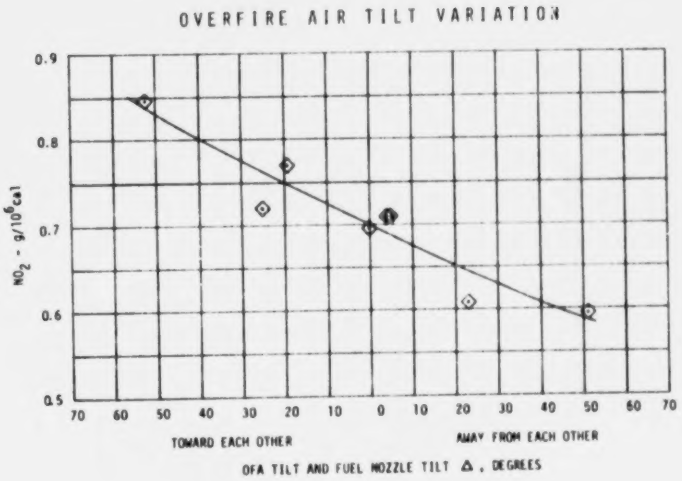


Fig. 15: NO_2 vs OFA tilt and fuel nozzle tilt differential, OFA tilt variation

forced down into the raised firing zone. At this point, where the combined fuel nozzle and OFA tilt differential was 52 degrees toward each other, the NO_x emission level reached a maximum of 0.846 g/10^6 cal.

CO emission levels exhibited an increase as the tilt differential increased; however, enough total excess air was available to maintain an acceptable emission level as shown in Fig. 16.

Flame stability became a limiting factor as the tilts move substantially away from each other (40 - 50 degrees). NO_x emission levels decreased to 0.596 g/10^6 cal; however, the CO emission levels increased and the fire appeared less stable. Maintaining the fuel nozzle tilts and OFA tilts at approximately equal tilt angles resulted in acceptable flame stability as well as reduced NO_x emission levels.

For all OFA tilt variation tests, the NO_x emission level obtained was well below the EPA limit of 1.26 g/10^6 cal.

Load Variation at Optimum Conditions

Tests were conducted to evaluate unit performance and emission levels at optimum operating conditions as determined during the overfire air variation tests. Tests were conducted over the unit load range at vary-

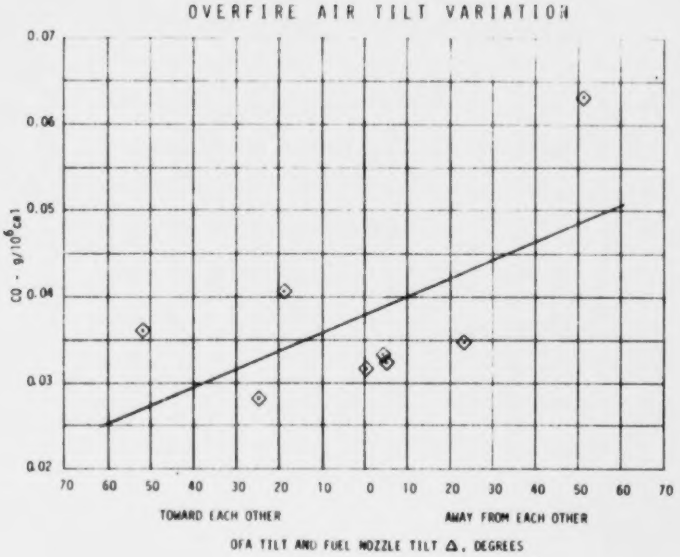


Fig. 16: CO vs OFA tilt and fuel nozzle tilt differential, OFA tilt variation

ing furnace waterwall slagging conditions. The NO_x emission level results of this series of test versus unit loading, expressed as main steam flow, are shown in Fig. 17.

The wide range of NO_2 levels obtained, particularly during the baseline tests are due to variations in unit operating parameters such as excess air level. During the optimization tests, total excess air at the unit economizer outlet was maintained between 20 and 28% at full and 3/4 load and 4[illegible] to 47% at 1/2 load with fuel nozzle tilts varied, as required, to maintain acceptable reheat and superheat outlet temperatures. Also, minimum excess air levels were established on the basis of maintaining acceptable CO emission levels and flame stability.

Furnace Performance

During the test program, furnace performance was monitored by use of chordal thermocouples installed in the furnace waterwalls. Temperatures and corresponding absorption rates were found to vary significantly with wall slag conditions making data interpretation difficult. The method finally arrived at as representing an accurate indication of furnace performance was as follows:

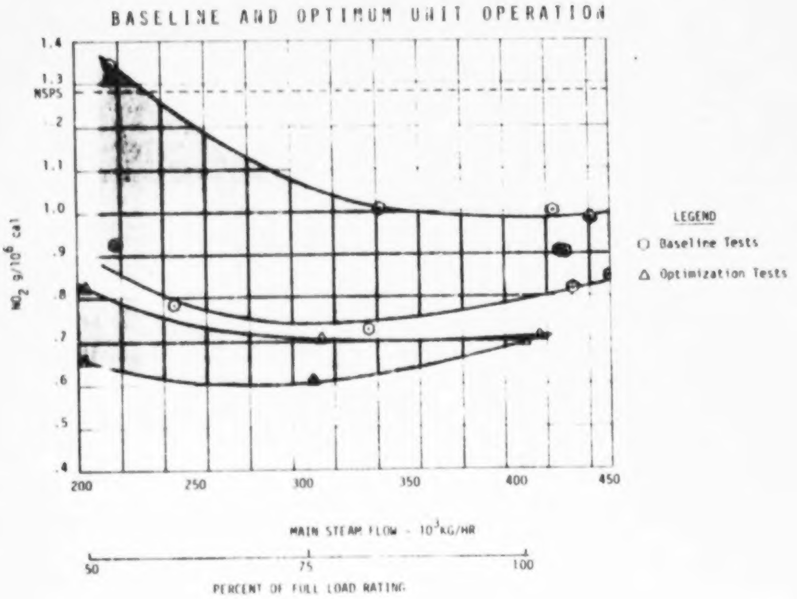


Fig. 17: NO_2 vs main steam flow, ranges for normal and optimum operation

The front and right side wall centertube profiles were determined and the average of these plotted as shown in Fig. 18. It should be noted that the maximum and minimum profiles shown do not represent individual walls in every case, i.e., at given furnace elevations the maximum rate shown may switch from wall to wall.

For comparison of optimum and normal unit operation with respect to furnace performance, three full load tests with similar furnace slagging conditions, etc., were selected. The average centerline profiles for these tests were determined and plotted together as shown in Fig. 19. Furnace performance remained essentially unchanged when furnace slagging effects were taken into account.

Waterwall Corrosion Coupon Evaluation

Following completion of the steady state phases of the baseline, biased firing, and overfire air test programs, 30-day waterwall corrosion coupon evaluations were performed to determine whether any measurable changes in coupon weight losses could be obtained for the various firing modes studied. The individual probes were exposed at

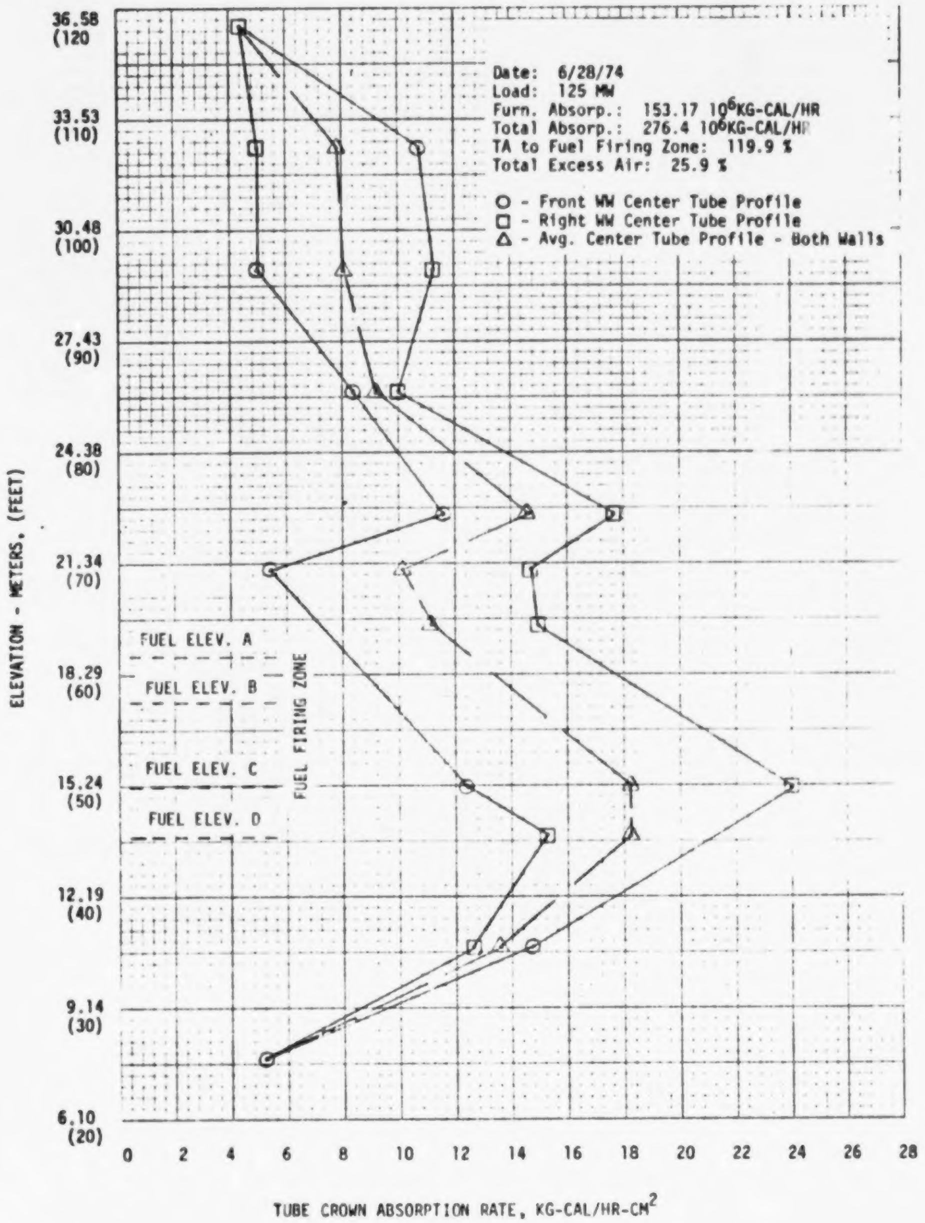
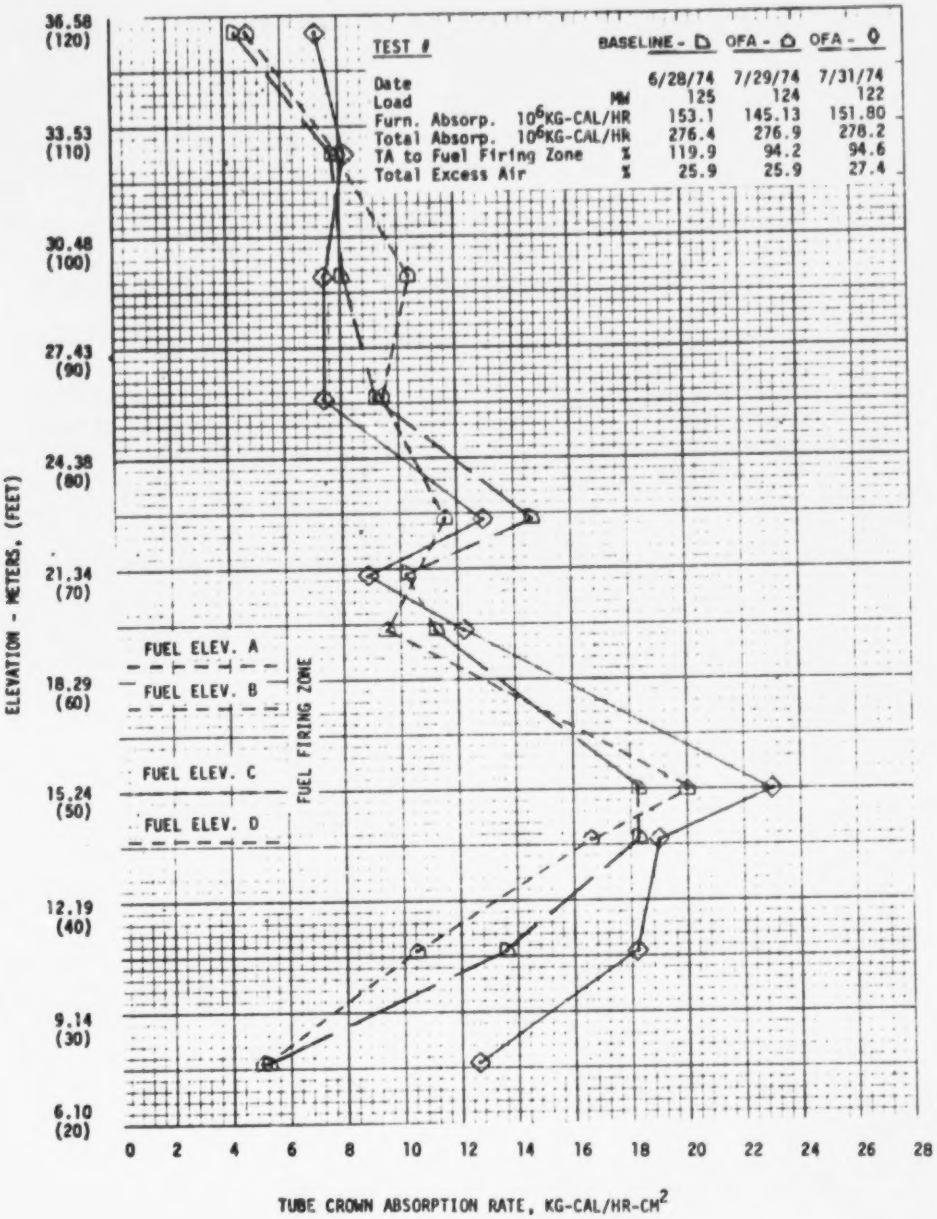


Fig. 18: Average centerline absorption profile -- full load operation



TEST #		BASELINE - ◻	OFA - ⌂	OFA - ◊
Date		6/28/74	7/29/74	7/31/74
Load	MW	125	124	122
Furn. Absorp.	10^6KG-CAL/HR	153.1	145.13	151.80
Total Absorp.	10^6KG-CAL/HR	276.4	276.9	278.2
TA to Fuel Firing Zone	%	119.9	94.2	94.6
Total Excess Air	%	25.9	25.9	27.4

Fig. 19: Average centerline absorption profile for all tests -- full load operation with and without overfire air

five locations on the furnace wall with coupon temperatures being maintained at the same levels for each 30-day run.

The individual coupon weights were determined before and after each 30-day test and the individual coupon and average probe weight losses determined. The weight losses calculated for the biased and overfire air portion of the test program were found to be greater than those for the baseline test. The average weight losses for all five probes were:

Baseline	Biased Firing	Overfire Air
2.6381 mg/cm^2	4.6429 mg/cm^2	4.4419 mg/cm^2

These values are within the range of losses which would be expected for oxidation of carbon steel for a 30-day period. To verify this premise, control studies were conducted in C-E's Kreisinger Development Laboratory using probes exposed during the biased firing study. These probes were cleaned and prepared in an identical manner to those used for furnace exposure and placed in a muffled furnace for 30 and 60-day exposures at 400 C with a fresh air exchange. The test results were as follows:

Probe	Wt. Loss mg/cm^2 - 30 days
M (30 Day)	4.7999
Q (30 Day)	4.7741
R (60 Day)	5.1571/2 = 2.5785
B (60 Day)	8.3493/2 = 4.1746

These results indicate that the test coupons oxidized more rapidly during the first 30 days exposure with average weight losses decreasing in the second 30 days. Based on these results, it appears that the differences in weight losses observed during the test program are within the ranges to be expected from oxidation alone.

SUMMARY

Under normal unit operating conditions without the use of overfire air, excess air variation is the most effective means of controlling NO_x emission levels. The use of overfire air provided a method of further reducing fuel firing zone stoichiometries while maintaining acceptable overall unit excess air and CO emission levels. The use of overfire air did not affect unit performance and results of the 30-day corrosion coupon runs indicate that longer term operation could be achieved without significantly affecting unit operating procedures. Longer term corrosion studies of a year or longer would be required before any definite conclusions concerning corrosion effects could be established.

The results of this study indicate that variables normally used to control boiler operation should not be considered as NO_x controls with coal firing. These variables include unit load, nozzle tilts, damper positions, and total excess air when overfire air is employed.

REFERENCE

1. CRAWFORD, A. P., MANNY, E. H. and BARTOK, W., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions from Utility Boilers," EPA-650/2-74-066, June 1974.

3:40 p.m.
Overfire Air as an NO_x Control Technique for Tangential Coal-Fired Boilers
Ambrose P. Selker, Combustion Engineering

Q: When was this last experimental work done?

A: The last test work, you mean? It was completed right around the end of last year. We do have a follow-on study on Western coals. We got the first baseline corrosion coupon results back, and they fell in between the baseline and OFA numbers I got on this unit.

Q: Did you notice in the off-stochiometric combustion mode if there was any change, any observed change in slagging characteristics between normal firing and low NO_x firing?

A: I am going to answer that in two ways. First, we did not see an adverse change in furnace slagging. In other words, it didn't change unit operation where we had to change retractable soot blower or wallblower blowing cycles or something like that. Secondly, when we did try to run the heavily slagged test with the overfire system in operation, we would let the unit go for 24-48 hours without wall blowing and come in and look at it, and it would be dirty everywhere but the firing zone. So we did have trouble getting the firing zone to slag with the overfire air system in operation.

Q: Would you care to elaborate on what you consider the slagging characteristics of the fuel or the ash of the coal that was tested?

A: It wasn't a bad slagging coal; also, we have a unit with a relatively low heat release rate here. A pretty good quality coal. Now, this coal run in other units in the same station where you are talking about higher heat release units and so forth is still not a bad slagging coal.

* * *

Q: Has Riley had any similar or totally different experience in their own work?

A: In some cases we have had increased slagging conditions and in other cases decreased slagging. In some cases with combined or overfire air conditions, we improved the carbon loss conditions, acually decreased NO_x by a factor of 2 and decreased carbon loss by a factor of 2, which was not anticipated. So we have had it go both ways.

* * *

Q: Do you feel that the corrosion rates that you obtained on, let's say, a low NO_x firing mode, the differences over base firing, are really significant?

A: I don't believe they are significant; I'll tell you why. What I showed you were average rates; they were the average of 5 probes, 4 coupons apiece. That is, 20 coupons. In the study where we had the low average, we had some coupons at very high rates. Where we had the high average, we had some with very low rates. There was a lot of overlapping that didn't actually show up in this average presentation I have here. It is in

the final report though...the actual numbers for each coupon.
Are you aware of the work we did on a prior EPA program where we showed no significant difference for corrosion rates? [Reference Exxon field tests.]

Q: This is on Barry No. 4?

A: On more than just Barry.

Q: Right.

A: Tomorrow I will present some more data.
I don't know why we saw the difference. I think it is a fluke. I really do, right now, but I can't prove that. We are going to find out in the Western coal program, hopefully, whether or not we would get the difference.

Q: I don't think anywhere in your paper you give us the levels of the fuel nitrogen. You made some reference that they increased at one point, but could you give us an idea of how much of the NO_x that you were measuring could be attributed to fuel nitrogen?

A: To answer the first part of your question, the fuel nitrogen levels ran from approximately 0.9 and 1% up to 1.5 or 1.6%, something like this. How much is attributable to it, we haven't really established that yet. I don't know, maybe it is 50%, maybe it is 100%.

Q: Some work done by a very distinguished visitor, Mr. David Pershing, with argon-oxygen experiments in a pilot scale unit, has indicated that for coal firing fuel nitrogen conversion can be quite high, perhaps 70% or more. Is that about right, Dave?

A: Of the total, yes. Now what the split is, I am not sure that we know that yet.

Q: I'd like to make some comments regarding the Western Coal Program that Ambrose has mentioned. We have a follow-on program with Combustion Engineering, that is looking at overfire air firing on two units of new design that were built with the overfire air as an extended wind box design. One is the Huntington Canyon Unit of Utah Power and Light, and the other is the Columbia Unit of Wisconsin Power and Light. One will fire a Western coal and one will fire a bituminous. So, we hope to relate the effect of designs built as extended windboxes versus retrofit; we hope to be able to relate the effect of the unit size -- the Barry unit was 125 megawatts, the two new units are about 400 megawatts, and we hope to be able to get an insight as to the effect of the fuel itself. And then, responding to Ambrose's conclusion or recommendation regarding further work in the corrosion area, we are planning, if we get the money from our friends in Washington, to start a more detailed corrosion program which would be sort of a monitoring type activity where we would select one or two units that were equipped with overfire air and try to keep sort of a continuous monitoring of the corrosion rates on a couple of boilers to establish some longer term data than we've been able to get thus far. Technically, our corrosion runs have been of 30-day duration. We'd like to extend that to 6 months to a year if we can.

CONTROL OF NO_x FORMATION IN WALL COAL-FIRED BOILERS

By

Gerald A. Hollinden, James R. Crooks

N. D. Moore and R. L. Zielke

Power Research Staff

Tennessee Valley Authority

And

Chris Gottschalk

Division Power Production

Tennessee Valley Authority

Preceding page blank

This paper has been reviewed by the Environmental Protection Agency and approved for publication. The paper summarizes data taken from a joint EPA-TVA Study (Interagency agreement EPA-IAG-137D), entitled "Control of NO_x Formation in Wall Coal-Fired Utility Boilers." Approval by EPA does not signify that the contents necessarily reflect the views and policies of the agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use. Dr. David G. Lachapelle served as EPA project officer.

ABSTRACT

It has been shown in previous work that biased firing techniques effectively reduce NO_x emissions; however, its long-term effects on corrosion, slagging, and general thermal and operational performance were not evaluated. The objective of this study was to provide quantitative information from which biased firing techniques would be evaluated as a method for control of NO_x formation with respect to its long-term effects on boiler corrosion, slagging, thermal efficiency, and operational performance.

In order to accomplish the objective, particulate and gaseous data were taken for a number of boiler load and firing patterns. In addition, two separate furnace corrosion measurement techniques were employed during long term runs.

Analysis of the gaseous emission data showed that certain combustion modifications can reduce NO_x emissions from 30 to 50 percent depending on the load and the burner configuration utilized.

The collected and dried particulate was analyzed for unburnt carbon. It was observed that the difference between baseline and the "low NO_x" condition was significant. In certain cases the carbon losses were more than double for the "low NO_x" case when compared to normal firing. This is an important factor to investigate further.

Of primary importance was the preliminary finding that for the "low NO_x" operating mode, both corrosion measurement techniques indicated a loss of tube metal significantly higher than that for normal boiler operation. The most apparent tube metal loss occurred on the side wall. More data will be obtained to further quantify this finding.

Introduction

In the last few years, TVA has participated in several research programs aimed at both identifying and reducing NO_x emissions from coal-fired boilers and, to a lesser extent, from oil-and gas-fired combustion turbines.[1] The overall results provided information on control of NO_x formation. However, there remained lack of information concerning boiler performance and efficiencies.

The major combustion operating parameters investigated in the past studies were excess air level and staged or biased firing patterns. These parameters were investigated mainly at full or slightly reduced load conditions.

The effectiveness of combustion modifications will vary with the individual boiler. For example, during the earlier studies it was shown that at full load conditions NO_x emissions could be reduced by approximately 30% over uncontrolled operation in certain boilers. The NO_x emissions were reduced by firing the operating burners in the lower burner rows with substoichiometric quantities of air and supplying the remaining air required through the burners in the upper row.

The purpose of the present TVA-EPA study has been to obtain more detailed information primarily on possible corrosion and efficiency losses that might occur while utilizing biased firing conditions as a control measure for NO_x.

The approach used in this field testing was first to characterize baseline and "low NO_x" firing condition. Using these results the operating conditions for NO_x emission control were defined. Second, the boiler was operated under the conditions for emission control while particulate tests were run to evaluate ignition losses and overall boiler efficiency. Lastly, two long-term (300 hrs) corrosion tests were run to determine waste rates. Corrosion rates were determined by two separate methods. In one method, actual boiler tube wall thickness measurements were made before and after the testing program. The second method involved the installation of air-cooled carbon steel coupons exposed in the vicinity of the furnace wall tubes. The coupons were used during the long-term corrosion tests. A weight difference method was used on the coupons to determine the mils/yr loss rate.

Test Program

The major objective of this study was to determine whether any significant operating problems occur during long range NO_x control testing -- such as reduction in boiler performance efficiency, corrosion, increased particulate loadings, or higher slagging rates.

To accomplish the objective, a boiler was chosen with enough operational flexibility to permit a thorough evaluation of many biased firing combustion modes. Widows Creek Unit 5 was selected. This Babcock and Wilcox unit has the following principal features: single pass, divided furnace, water wall, dry bottom, radiant, reheat, 850,000 lb. steam per hr., 1825 psig (at superheater outlet), 1003°F (at superheater outlet), 125 MW, pulverized bituminous coal, wall fired. The unit went into service in September, 1955. Unit 5 has a sister (Unit 6) that was used as a control for corrosion rate determinations for the long term tests.

The test program was designed to characterize the pollutant emissions and process variables of both baseline and biased-firing conditions. The evaluation consisted of 47 separate tests. Table 1 depicts the conditions for each run. Figure 1 shows the numbering of the 16 burners inside Unit #5. These individual tests vary the amount of coal and secondary air flow through the burners. All necessary information concerning the boiler operation (steam flow, air flow, etc) was recorded along with the different emission levels of NO, NO_x, CO, CO_2, O_2, and SO_2 for all test series.

During both the baseline and biased firing characterization test program, the levels of gaseous emissions were continuously monitored and recorded. The baseline emission levels of NO_x were used for comparison with both low air and biased firing techniques. From an evaluation of the characterization runs (47 tests), both baseline conditions and selected operating conditions that significantly reduced NO_x levels were run again at each load condition (50,75,100, 125 MW). The levels of NO_x, unburnt particulate carbon, total particulate and boiler efficiencies were compared for each of these operating conditions.

Data Collection and Measurement

A mobile analytical van capable of monitoring the combustion products was fabricated by an outside firm for use in the program. The system is by necessity sophisticated, utilizing the accepted methods in analytically measuring the components of the gas sample. The gas sample was handled carefully to avoid contamination or loss. The van is equipped with a nondispersive infrared analyzer to measure CO and CO_2, a nondispersive ultraviolet analyzer to measure SO_2, a polargraphic O_2 analyzer, a chemiluminescent analyzer for measuring NO and NO_x, and a flame ionization detector for hydrocarbon analysis. Table 2 depicts the equipment used and the ranges of detection for each. All necessary calibration gases of appropriate concentrations were stored in cylinders employing dry nitrogen as the carrier gas. The instruments were calibrated daily before testing and periodically throughout each shift to assure accurate analysis.

In running field tests, the samples were drawn before the air preheater section from six zones in each duct providing 12 sample regions per boiler. This sampling procedure reasonably assures a representative sample. The sample is removed from the boiler under vacuum through stainless steel probes fitted with metal particulate filters. The sample passes through teflon lines and its temperature is maintained above 250°F until it reaches the gas cooler. The sample is refrigerated to a 35°F dew point to remove water vapor and then is sent to the analytical van for analysis. Figure 2 illustrates the flue gas sampling and conditioning system.

Four Research Appliance Company particulate sampling trains (EPA-method 5) were used. This setup included four sampling boxes equipped with 4-inch filters and probes, and two sets of isokinetic pumping systems. The measurements were taken after the air preheater section of the boiler. Each duct was divided into 12 sample regions to assure a fairly representive sample. The data was used to calculate the amount of particulate emitted (gr/scf) and the unburnt combustibles retained in the flyash. The latter was obtained from an ignition loss analysis.

Two different methods were used to obtain corrosion rate data. The first method relied on actual tube wall measurements prior to beginning the study and after its completion of both Units 5 and 6. The tubes were cleaned to bare metal and then measured with a Krautkamer USK5 Ultrasonic Minature Flaw Detector.

The instrument was calibrated frequently with a standard calibration block. More than fifty measurements at different locations were made on each boiler wall, totally at least 400 measurements per boiler. Similar measurements were taken after completion of the testing portion of the program.

The second approach (for corrosion detection) utilized corrosion probes exposed in both the control boiler (normal firing--Unit 6) and the test boiler (biased firing--Unit 5). The temperature of the SA192 carbon steel corrosion coupon was set at approximately 650°F for each boiler. Two separate corrosion coupon tests were run. The coupons were exposed to the test atmosphere with range of times from 315 to 755 hrs. After exposure, the slag was removed and saved, and the coupons were then cleaned with a mild acid pickling solution. The coupons were re-weighed to determine any weight loss. Figures 3 and 4 illustrate the details of the corrosion probes. The probe design is similar to Combustion Engineering's which basically consists of two concentric pipes. Cooling air from the plant air supply enters the tube-shaped coupons through a 1/2-inch stainless steel tube roughly centered inside the coupons. The coupons (outside surface) are exposed to the furnace atmosphere. The amount of cooling air is controlled automatically to maintain the set-point temperature. Two thermocouples are used for each probe--one for controlling the temperature and the other for recording the temperature. The cooling air travels back through a 2-inch extention pipe for discharge outside of the boiler. Therefore, the cooling air does not interfere with the test. Figure 5 gives the location of the probes and figure 6 gives the operating procedures utilized throughout this portion of the test.

Data Evaluation

NO_x: The analysis of the short term NO_x test program shows that the(lbs/MM Btu's) of NO_x can be reduced by staged firing and lowering the excess air from the normal levels at each level of load generation. It is important to note that the excess air levels increase as the load of the unit is reduced and that lowering load without either staged firing or a reduction in excess air from the normal level for that load will not in general reduce the NO_x (lbs/MM Btu's).

Table 3 depicts the emission levels of O_2, CO_2, CO, SO_2, and NO_x for each short term test. Figure 7 is a graph of NO_x (lbs/MM Btu's) vs O_2% for normal firing modes at 125, 100, 75, and 50 MW. At 50 MW, there were two distinct coals (in terms of heat content) used. The higher Btu coal content coal gave the lower levels of NO_x and this higher Btu coal was more representative of the majority of coal burned during these tests. Utilizing the data at 50 MW obtained with the higher Btu content coal and the data at 125, 100, and 75 MW, the following relationships have been developed for normal firing conditions:

$$\log_e \hat{O}_2 = 2.8358 - .0126\ \mathrm{MW} \qquad (1)$$

$$\log_e \hat{NO} = -1.9068 + .02923\ \mathrm{MW} - 0.000127\ \mathrm{MW}^2 \qquad (2)$$

$$\frac{d(\hat{NO})}{d(\hat{O}_2)} = \frac{d(\hat{NO})}{d(\mathrm{MW})} \cdot \frac{d(\mathrm{MW})}{d(\hat{O}_2)} = \frac{(\hat{NO})\ (.8)\ (-1.15 + 5.08 \log_e \hat{NO})^{1/2}}{\hat{O}_2} \qquad (3)$$

where $\hat{O}_2$ = normal % oxygen content

$\hat{NO}$ = normal oxides of nitrogen (lbs/MM Btu's)

MW = megawatt load

Therefore, given the megawatt load, the expected O_2 level for normal firing can be determined by equation (1), the NO emission can be determined by equation (2), and the rate of change of NO with respect to O_2 can be determined by equation (3) and thus the required level of O_2 reduction necessary to meet a specified emission level.

As stated earlier, NO_x emissions can be reduced by biased firing at each level of load generation. Figures 8-11 are graphs of NO_x (lbs/MM Btu's) vs O_2% for different biased firing patterns and load conditions. The approximate range of testing for each biased firing condition is represented by the length of the line on each figure. Extrapolation is not recommended.

Particulate: The particulate emission data are summarized in Table 4. Total quantities of particulate increased for the biased firing tests but were not considered significant. However, carbon losses increased significantly, particularly the relative differences at high loads. Table 5 illustrates the effect of ignition losses for both types of firing as a function of increased fuel operating costs.

Boiler Efficiency: Boiler efficiencies were calculated using the ASME STEAM Generating Units, Power TEST Codes, using the Abbreviated Efficiency Test Heat Loss Method. The assumptions made were that no combustibles remained in the bottom ash and that the unmeasured losses were 0.5 percent. Table 6 summarizes the calculated boiler efficiencies and other pertinent information for normal and biased-firing conditions. Figure 12 is a graph of mean boiler efficiency versus load (MW). A consistent reduction of efficiencies throughout the load range of the boiler is apparent under biased firing conditions.

Corrosion: A summary of the boiler tube corrosion measurements taken on Units 5 (biased firing) and 6 (normal firing) is contained in Table 7. The following conclusions have been drawn based upon a statistical analysis of the data:

(1) Unit 5, B furnace, side wall, lost an average of 7 mils thickness from the time the wall was first measured ("before" in Table 7) until the wall was again measured ("after" in Table 7). The loss was

statistically significant at $\alpha = .05$ or only 5 percent of time will this difference be due to random variation, and not a true loss of wall thickness.

(2) Unit 5, B furnace, division wall, lost an average of 3 mils thickness. The loss was statistically significant at $\alpha = .08$.

(3) No other walls tested both before and after showed a statistically significant ($\alpha = .10$) loss.

(4) All walls in Unit 6, B furnace, showed a significant gain in wall thickness.

(5) Comparison of Unit 6, B furnace, after measurements, Unit 5, B furnace, before measurements, and Unit 5, A furnace, before measurements, shows no difference, both on an overall average, and a wall to wall average.

(6) The consistent differences on Unit 6, B furnace, on a wall to wall comparison, in conjunction with the conclusion above, point to a calibration error in the measurements on Unit 6, before measurements, of approximately 5 mils.

Based on the conclusion in #6 above, the tube wall measurements for the B furnace on Unit 6 reflect this correction factor in Table 7.

It is apparent that more data is needed to further quantify the magnitude of corrosion. The unit is presently on line due to the load requirements on the power system, but as soon as it can be taken off line a thorough tube wall measurement will be performed.

The corrosion probes were used as an indicator of possible corrosive atmospheres in the boiler and were not intended to supply any significant quantitative date. However, the results shown in Tables 8 and 9 are quite interesting. For meaningful comparisons, probe 1 can be compared with probe 3 and probe 2 with probes 4 and 5. The comparison cases are for those probes in similar locations in the boiler. In the first series of tests (Table 8), it is apparent that between 2 and 5 times the corrosion rate (mils/yr) occurred on those elements in the "low NO_x" mode boiler. In the second series of tests (Table 9), the data shows significant corrosion increases when comparing probe 4 (biased firing) to probe 2 (normal firing); however, little difference is shown for the other location.

Conclusions

Even though much data has recently been published in the areas of NO_x control, there has been little if any definitive published data on coal-fired units where such control has been correlated to particulate emissions, boiler efficiency and corrosion. However, based on the results of this test program the following tentative conclusions can be made:

- Certain combustion modifications can reduce NO_x emissions from 30 to 50 percent depending on the load and the burner configuration utilized for pulverized coal-fired boilers.

- Carbon losses in the particulate will increase for biased firing conditions. This carbon increase will reduce the conductivity of the ash somewhat and could affect ESP efficiency. Total particulate increases, however, were not considered significant.

- A consistent reduction of boiler efficiencies throughout the load range of the boiler is apparent under biased firing conditions.

- Corrosive atmospheres will prevail in the boiler under biased firing conditions. Such atmospheres appear from preliminary information to cause significant water tube losses in certain areas of the boiler.

REFERENCES

1. Hollinden, G. A. et.al., "NO_x Control at TVA Coal-Fired Steam Plants," presented at ASME Air Pollution Control Division National Symposium, Philadelphia, Pennsylvania, April 24 - 25, 1973.

TABLE 1

Test Program for Baseline and Biased Firing Emissions Studies At Widows Creek Unit 5

Test Program

			Burners	
Run	Boiler Load (MW)	Excess Air	Firing Coal	On Air Only
1	125	Normal	16	0
2	125	Low	16	0
3	125	Normal	14	A_1, A_4
4	125	Normal	14	D_1, D_4
5	125	Normal	14	B_2, B_3
6	125	Normal	14	C_2, C_3
7	125	Low	14	A_1, A_4
8	125	Low	14	D_1, D_4
9	125	Low	14	B_2, B_3
10	125	Low	14	C_2, C_3
11	100	Normal	16	0
12	100	Low	16	0
13	100	Normal	12	A_1, A_4, D_1, D_4
14	100	Normal	12	B_2, B_3, C_2, C_3
15	100	Normal	12	A_1, A_2, A_3, A_4
16	100	Normal	12	C_1, C_2, C_3, C_4
17	100	Normal	12	D_1, D_2, D_3, D_4
18	100	Normal	12	A_2, A_3, D_1, D_4
19	100	Low	12	A_1, A_4, D_1, D_4
20	100	Low	12	B_2, B_3, C_2, C_3
21	100	Low	12	A_1, A_2, A_3, A_4
22	100	Low	12	C_1, C_2, C_3, C_4
23	100	Low	12	D_1, D_2, D_3, D_4
24	100	Low	12	A_2, A_3, D_1, D_4
25	75*	Normal	12	0
26	75	Low	12	0
27	75	Normal	10	B_1, B_4
28	75	Normal	10	C_2, C_3
29	75	Normal	10	D_1, D_4
30	75	Low	10	B_1, B_4
31	75	Low	10	C_2, C_3
32	75	Low	10	D_1, D_4
33	75	Normal	8	B_1, B_2, B_3, B_4

Table 1 (cont)

			Burners	
Run	Boiler Load (MW)	Excess Air	Firing Coal	On Air Only
34	75	Normal	8	C_1, C_2, C_3, C_4
35	75	Normal	8	B_1, B_4, D_1, D_4
36	75	Low	8	B_1, B_2, B_3, B_4
37	75	Low	8	C_1, C_2, C_3, C_4
38	75	Low	8	B_1, B_4, D_1, D_4
39	50[A]	Normal	8	0
40	50[A]	Low	8	0
41	50[B]	Normal	8	0
42	50[B]	Low	8	0
43	50[A]	Normal	6	B_2, B_3
44	50[A]	Normal	6	C_1, C_4
45	50[A]	Low	6	B_2, B_3
46	50[A]	Low	6	C_1, C_4
47[**]	50[A]	Low	6	B_1, B_4

---

[*] In all runs at 75 MW, the A mill is off.

[A] In these runs, the A and D mills are off.

[B] In these runs, the A and C mills are off.

[**] Used in particulate series only

TABLE 2

	Instruments	Technique	Measuring Range
1.	NO, NO$_x$ Analyzer Thermo Electron Model 10A	Chemiluminscent, negative pressure	0-10 ppm 0-25 ppm 0-100 ppm 0-250 ppm 0-1000 ppm 0-2500 ppm
2.	CO Analyzer Beckman #864	nondispersive infrared absorption	0-1000 ppm 0-5000 ppm
3.	CO$_2$ Analyzer Beckman #864	nondispersive infrared absorption	0-5% 0-20%
4.	SO$_2$ Analyzer DuPont #400	nondispersive ultraviolet absorption	0-1000 ppm 0-5000 ppm
5.	O$_2$ Analyzer Beckman (742 Model)	Polargraphic sensor	0-5% 0-10% 0-25%
6.	Hydrocarbon Analyzer Beckman #400	flame ionization	0-1000 ppm 5-100,000 ppm

CONTROL OF NO$_x$ FORMATION IN WALL, COAL-FIRED UTILITY BOILERS
SHORT-TERM BIASED FIRING TEST AT WIDOWS CREEK UNIT 5

Date	Run No.	Load	CO$_2$% As Measured A-duct	CO$_2$% As Measured B-duct	O$_2$% A-duct	O$_2$% B-duct	NO$_x$ (ppm) @ 3% O$_2$ A-duct	NO$_x$ (ppm) @ 3% O$_2$ B-duct	CO (ppm) @ 3% O$_2$ A-duct	CO (ppm) @ 3% O$_2$ B-duct	SO$_2$ (ppm) @ 3% O$_2$ A-duct	SO$_2$ (ppm) @ 3% O$_2$ B-duct	Lb, NO$_x$ / 10^6 Btu
11-5-74	2A	125	16.0	15.2	2.0	2.9	491	513			2226	2138	0.70
11-5-74	2B	126	17.0	16.1	1.5	2.6	441	479	876	487	1606	1536	0.63
11-6-74	26B	55	15.7	15.2	3.3	4.0	254	294	85	172	885	794	0.32
11-6-74	26A	60	16.0	15.5	3.6	4.1	250	279	143	162	931	820	0.32
11-7-74	7A	108	16.9	16.7	3.2	2.9	413	408	307	163	3074	3063	0.51
11-7-74	1B	120	15.4	15.0	2.6	3.1	528	589	22	20	3404	3399	0.70
11-7-74	1A	120	15.2	15.1	3.2	3.1	580	585	20	20	3550	3349	0.70
11-8-74	15B	93	15.5	15.4	3.6	3.6	387	375	47	230	683	685	0.48
11-8-74	15A	93	16.2	15.8	3.9	4.2	406	416	17	47	710	716	0.48
11-8-74	21A	93	15.8	15.4	3.1	3.3	372	380	40	213	784	757	0.46
11-12-74	16A	100	13.5	14.3	5.8	5.3	481	569	31	39	841	860	0.64
11-12-74	22A	100	15.3	16.4	4.4	3.2	382	409	281	576	787	801	0.48
11-13-74	7B	123	16.7	16.1	2.6	2.9	430	451	327	521	724	746	0.54
11-13-74	3A	124	16.6	16.4	2.9	3.7	485	518	74	233	698	722	0.61
11-14-74	4A	118	13.9	13.8	4.6	4.9	729	740	10	8	758	743	1.01
11-14-74	8A	117	15.7	14.8	3.3	4.8	608	620	22	22	869	898	0.85
11-19-74	5A	114	15.1	14.6	3.4	4.4	622	523	23	22	1381	1410	0.79
11-19-74	9A	110	17.2	15.6	3.8	4.1	551	405	42	100	1486	1459	0.66

CONTROL OF NO_x FORMATION IN WALL, COAL-FIRED UTILITY BOILERS
SHORT-TERM BIASED FIRING TEST AT WIDOWS CREEK UNIT 5

Date	Run No.	Load	CO_2% As Measured		O_2%		NO_x (ppm) @ 3% O_2		CO (ppm) @ 3% O_2		SO_2 (ppm) @ 3% O_2		Lb, NO_x / 10^6 Btu
			A-duct	B-duct	A-duct	B-duct	A-duct	B-duct	A-duct	B-duct	A-duct	B-duct	
11-20-74	5B	125	15.7	15.7	3.5	3.8	640	548	64	65	977	1015	0.66
11-20-74	9B	120	19.1	18.3	1.4	2.3	474	452	1829	1019	955	924	0.63
11-21-74	10A	109	15.3	14.8	2.7	3.3	509	445	114	482	2262	2248	0.65
11-21-74	6A	110	15.6	14.8	4.0	4.6	641	505	21	34	2531	2509	0.79
12-11-74	12A	88	13.8	13.5	3.0	2.8	536	458	92	787	935	940	0.69
12-12-74	11B	99	15.8	15.5	2.7	3.2	482	570	45	33	1239	1284	0.72
12-12-74	12B	99	16.0	15.6	2.4	2.9	410	483	93	44	1810	1760	0.62
12-13-74	40A	48	12.0	10.6	7.6	8.8	538	600	13	15	817	818	0.78
12-13-74	39A	48	10.9	9.8	8.1	9.8	567	641	14	16	844	895	0.84
12-17-74	23A	90	14.3	13.4	3.3	4.4	472	594	216	39	1495	1443	0.73
12-17-74	17A	94	14.5	13.2	4.0	5.7	553	690	40	24	1154	1201	0.86
12-17-74	46A	46	12.0	9.7	8.1	10.3	478	640	61	47	900	890	0.77
12-17-74	44A	45	11.7	9.3	8.4	11.0	535	765	66	40	1087	1061	0.89
12-19-74	20A	100	13.9	13.6	2.6	3.0	386	350	688	481	1497	1590	0.51
12-19-74	14A	102	15.8	15.0	3.6	4.3	467	474	48	30	1531	1520	0.65
12-23-74	34A	67	13.3	12.2	6.1	7.6	346	376	31	36	3808	3913	0.49
12-23-74	37A	67	13.2	12.0	4.3	5.5	285	316	121	109	3709	3753	0.41
1-6-75	18A	97	14.3	14.3	6.4	6.2	518	448	30	44	3674	3690	0.67

CONTROL OF NO_x FORMATION IN WALL, COAL-FIRED UTILITY BOILERS
SHORT-TERM BIASED FIRING TEST AT WIDOWS CREEK UNIT 5

			CO_2% As Measured		O_2%		NO_x (ppm) @ 3% O_2		CO (ppm) @ 3% O_2		SO_2 (ppm) @ 3% O_2		
Date	**Run No.**	**Load**	**A-duct**	**B-duct**	**A-duct**	**B-duct**	**A-duct**	**B-duct**	**A-duct**	**B-duct**	**A-duct**	**B-duct**	**Lb. NO_x / 10^6 Btu**
1-6-75	24A	95	14.8	14.4	3.6	4.3	354	300	267	509	3464	3478	0.45
1-7-75	29A	75	13.8	12.4	6.8	7.6	538	449	28	27	1124	1062	0.68
1-7-75	32A	73	13.0	12.1	3.6	5.2	352	315	84	89	1177	1149	0.46
1-10-75	26D	74	15.8	13.8	3.9	5.3	383	399	354	62	916	943	0.54
1-10-75	25A	75	14.6	12.6	6.0	8.1	499	511	40	43	872	911	0.70
1-13-75	19A	99	15.0	14.9	3.6	4.2	451	416	124	181	3073	3108	0.60
1-13-75	13A	103	13.7	13.6	5.6	5.8	634	626	37	33	3859	4017	0.87
1-15-75	28A	76	13.9	12.5	6.3	7.9	517	535	38	43	983	1012	0.73
1-15-75	31A	75	16.2	15.4	3.7	4.5	356	336	46	327	999	976	0.48
1-16-75	42A	50	11.1	9.7	7.1	8.5	435	480	39	48	2449	2465	0.64
1-16-75	41A	50	11.8	10.4	8.8	10.4	547	572	46	56	2792	2952	0.78
1-17-75	43A	47	10.5	10.4	10.3	9.8	411	348	85	71	1920	1948	0.53
1-17-75	45A	47	10.4	10.5	8.1	8.1	358	293	64	59	1830	1788	0.44
1-21-75	27A	73	13.3	12.9	7.7	8.1	447	391	35	34	3339	3436	0.58
1-21-75	30	75	14.0	13.5	5.8	6.4	353	318	38	49	3187	3146	0.46
1-22-75	38A	64	14.3	13.5	4.9	5.9	304	343	108	67	1711	1694	0.45
1-22-75	36A	54	11.3	11.3	8.4	8.3	299	278	93	69	1302	1263	0.40

CONTROL OF NO_x FORMATION IN WALL, COAL-FIRED UTILITY BOILERS
SHORT-TERM BIASED FIRING TEST AT WIDOWS CREEK UNIT 5

			CO_2% As Measured		O_2%		NO_x (ppm) @ 3% O_2		CO (ppm) @ 3% O_2		SO_2 (ppm) @ 3% O_2		
Date	Run No.	Load	A-duct	B-duct	A-duct	B-duct	A-duct	B-duct	A-duct	B-duct	A-duct	B-duct	Lb. NO_x / 10^6 Btu
1-22-75	33A	63	10.6	10.3	10.4	10.3	422	391	65	62	1228	1271	0.56
1-22-75	35A	67	11.3	10.6	8.9	8.4	435	425	122	107	1147	1144	0.60

TABLE 4

CONTROL OF NO_x FORMATION IN WALL, COAL-FIRED UTILITY BOILERS

PARTICULATE TEST SUMMARY SHEET

Date	Run #	Load (MW)	Total Particulate Collected (Grams)	Grain Loading (Grains/SCF)**		Ignition Loss (%)	Lb, NO_x 10^6 Btu
				A-Duct	B-Duct		
2-10-75	5-1A	125	8.3021	0.14*	2.09	6.8	0.86
2-11-75	6-1B	132	28.3505	2.86	3.67	9.0	0.79
2-12-75	7-25A	76	19.7784	3.04	3.61	9.0	0.59
2-12-75	8-39A	50	20.2631	3.12	3.66	13.4	0.52
2-13-75	9-39B	47	14.4670	3.48	1.74*	9.9	0.51
2-13-75	10-39C	47	17.7158	3.03	3.41	9.2	0.43
2-14-75	11-1C	128	51.5017	5.79	5.20	6.2	0.83
2-14-75	12-25B	75	38.6057	4.74	5.61	5.9	0.78
2-18-75	13-25C	74	39.8893	5.93	4.74	7.4	0.75
2-19-75	14-11A	105	53.3383	7.13	7.39	4.1	0.83
2-21-75	15-11B	102	56.3518	7.41	7.14	3.9	0.96
2-21-75	16-47A	44	30.9855	4.40	7.76	10.6	0.41

Date	Run #	Load (MW)	Total Particulate Collected (Grams)	Grain Loading (Grains/SCF)** A-Duct	Grain Loading (Grains/SCF)** B-Duct	Ignition Loss (%)	Lb, NO_x 10^6 Btu
2-25-75	17-7A	124	56.4179	7.81	7.94	8.1	0.54
2-25-75	18-7B	124	45.8457	6.26	6.26	8.7	0.52
2-26-75	19-47B	38	20.4108	3.87	3.53	9.3	0.60
2-27-75	20-21A	99	56.1627	7.26	7.53	15.1	0.54
2-27-75	21-21B	98	50.2269	6.72	7.97	15.5	0.55
2-28-75	22-30A	73	36.6043	6.70	6.45	8.4	0.50
2-28-75	23-30B	73	20.3671	2.48*	4.78	8.8	0.50
3-4-75	24-36A	53	21.1069	3.77	3.51	16.0	0.38
3-4-75	25-36B	52	17.5953	3.49	4.65	13.2	0.37

---

*Leak developed in EPA particulate sampler during test.

**Particulate collected with the EPA train on dry bases and gas volume corrected to 70°F at 29.92 inches of Hg.

TABLE 5

TEST	MW	ASH CONTENT (%)	IGNITION LOSS (%)	LOSS $/YR	COMMENTS
5-1A	125	10.2	6.8	41,000	Baseline, Normal Air*
6-1B	132	10.3	9.0	55,000	Baseline, Normal Air
11-1C	128	14.9	6.2	54,800	Baseline, Normal Air
17-7A	124	21.4	8.1	102,800	Biased, Low Air
18-7B	124	17.8	8.7	91,900	Biased, Low Air
14-11A	105	20.6	4.1	50,100	Baseline, Normal Air
15-11B	102	22.1	3.9	51,100	Baseline, Normal Air
20-21A	99	18.9	15.1	169,300	Biased, Low Air
21-21B	98	18.6	15.5	171,000	Biased, Low Air
7-25A	76	13.7	9.0	73,100	Baseline, Normal Air
12-25B	75	17.0	5.9	59,500	Baseline, Normal Air
13-25C	74	19.8	7.4	86,900	Baseline, Normal Air*
22-30A	73	19.4	8.4	96,700	Biased, Low Air
23-30B	73	16.8	8.8	87,700	Biased, Low Air
8-39A	50	14.4	13.4	114,500	Baseline, Normal Air*
9-39B	47	14.4	9.9	84,600	Baseline, Normal Air
10-39C	47	13.6	9.2	74,200	Baseline, Normal Air
16-47A	44	21.5	10.6	135,200	Biased, Low Air
19-47B	38	15.1	9.3	83,300	Biased, Low Air*
24-36A	53	14.0	16.0	132,900	Biased, Low Air
25-36B	52	14.1	13.2	110,400	Biased, Low Air

Based on Fiscal Report 1975

1. 8.989 Mils/Net KWH
2. Ave. Heat Rate of 10490 Btu/Net KWH
3. 70.78 cents/10^6 Btu

* = Interrupted Test

TABLE 6

SUMMARY OF BOILER PERFORMANCE CALCULATIONS

WIDOWS CREEK UNIT #5

FIRING MODE	TEST #	LOAD (MW)	%O_2*	lb NO_x 10^6 Btu (@ 3% O_2)	ASH %	IGNITION LOSS %	DRY GAS LOSS %	BOILER EFFICIENCY
Baseline	5-1A	125	4.6	0.86	10.2	6.8	6.37	87.42
Baseline	6-1B	132	3.7	0.79	10.3	9.0	6.00	87.44
Baseline	11-1C	128	4.2	0.83	14.9	6.2	5.85	87.74
Low NO_x	17-7A	124	3.7	0.54	21.4	8.1	5.78	86.91
Low NO_x	18-7B	124	2.9	0.52	17.8	8.7	5.54	87.59
Baseline	14-11A	105	5.7	0.83	20.6	4.1	5.48	88.42
Baseline	15-11B	102	6.7	0.96	22.1	3.9	6.45	87.55
Low NO_x	20-21A	99	5.3	0.54	18.9	15.1	5.60	86.46
Low NO_x	21-21B	98	5.7	0.55	18.6	15.5	6.70	84.68
Baseline	7-25A	76	7.5	0.59	13.7	9.0	7.18	86.03
Baseline	12-25B	75	8.5	0.78	17.0	5.9	7.36	86.13
Baseline	13-25C	74	8.9	0.75	19.8	7.4	6.12	87.00
Low NO_x	22-30A	73	6.6	0.50	19.4	8.4	8.04	84.55
Low NO_x	23-30B	73	7.0	0.50	16.8	8.8	7.33	85.16

TABLE 6

Continued

FIRING MODE	TEST #	LOAD (MW)	%O_2 *	lb NO_x 10^6 Btu (@3% O_2)	ASH %	IGNITION LOSS %	DRY GAS LOSS %	BOILER EFFICIENCY
Low NO_x	24-36A	53	8.3	0.38	14.0	16.0	7.54	84.27
Low NO_x	25-36B	52	9.1	0.37	14.1	13.2	8.58	83.53
Baseline	8-39A	50	9.3	0.52	14.4	13.4	8.31	84.15
Baseline	9-39B	47	9.6	0.51	14.4	9.9	8.92	84.47
Baseline	10-39C	47	9.1	0.43	13.6	9.2	8.82	85.01
Low NO_x	16-47A	44	7.5	0.41	21.5	10.6	6.98	85.22
Low NO_x	19-47B	38	8.5	0.60	15.1	9.3	8.16	84.17

---

*The %O_2 figure is the average of %O_2 in A & B duct.

TABLE 7

WIDOWS CREEK STEAM PLANT

UNIT 6

(CONTROL BOILER)

A FURNACE			B FURNACE			
WALL	BEFORE	AFTER	WALL	BEFORE	AFTER	EXTRAPOLATED CORROSION RATE (BIASED FIRING MILS/YR)
Burner	312[1]		Burner	314[1]	314	NS
Side	317[1]		Side	319[1]	319	NS
Front	319[1]		Front	315[1]	316	NS
Division	308[1]		Division	305[1]	306	NS

---

[1] = Corrected Values

NS = Not Significant (10% or greater)

TABLE 7
Cont.

WIDOWS CREEK STEAM PLANT

UNIT 5

(TEST BOILER)

A FURNACE			B FURNACE			
WALL	BEFORE	AFTER	WALL	BEFORE	AFTER	EXTRAPOLATED CORROSION RATE (BIASED FIRING MILS/YR
Burner	316	-	Burner	312	312	NS
Side	320		Side	319	312	37.8[2]
Front	316		Front	312	313	NS
Division	307		Division	307	304	11.8[3]

---

[2] = Significant at 5% or less

[3] = Significant at 8% or less

NS = Not Significant (10% or greater)

TABLE 8

LONG-TERM CORROSION STUDY

WIDOWS CREEK STEAM PLANT

UNITS NO. 5 & 6

SERIES 1

PROBE NO.	ELEMENT NO.	WEIGHT (GRAMS) BEFORE	WEIGHT (GRAMS) AFTER	% LOSS (GRAMS)	EXPOSURE TIME (T) (HOURS)	CORROSION RATE (MILS/YR)
2	2	134.2378	133.9924	0.18	365	8.2
	10	132.8183	132.5795	0.18	365	8.1
4	4	133.7756	132.6117	0.87	315	46.8
	12	135.1769	134.5688	0.45	315	23.4

TABLE 9

LONG-TERM CORROSION STUDY

WIDOWS CREEK STEAM PLANT

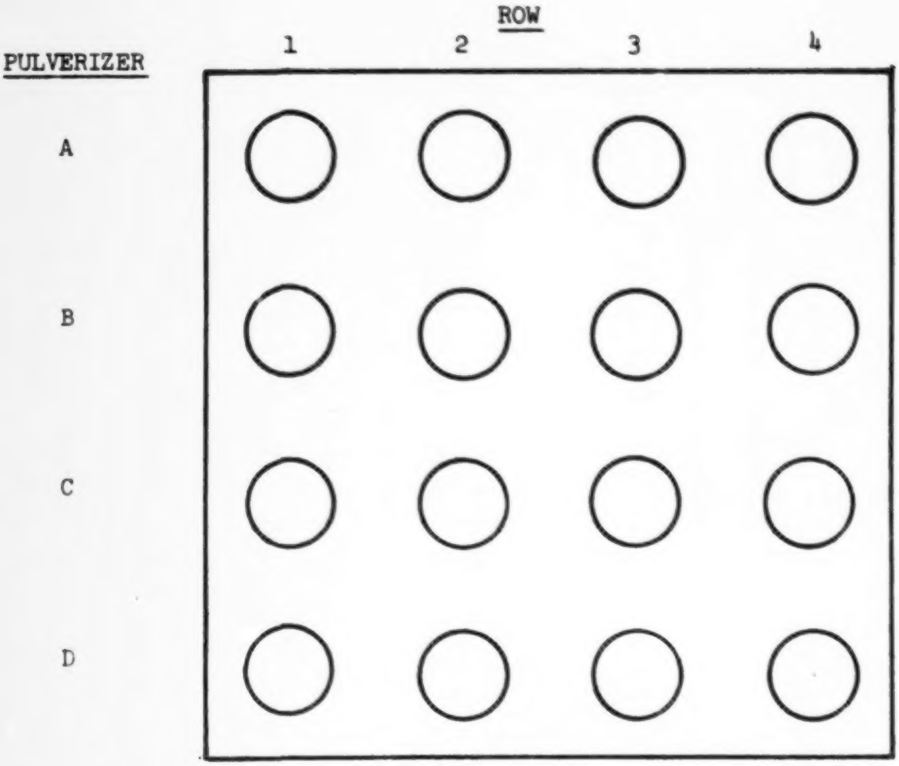
UNITS NO. 5 & 6

SERIES 1

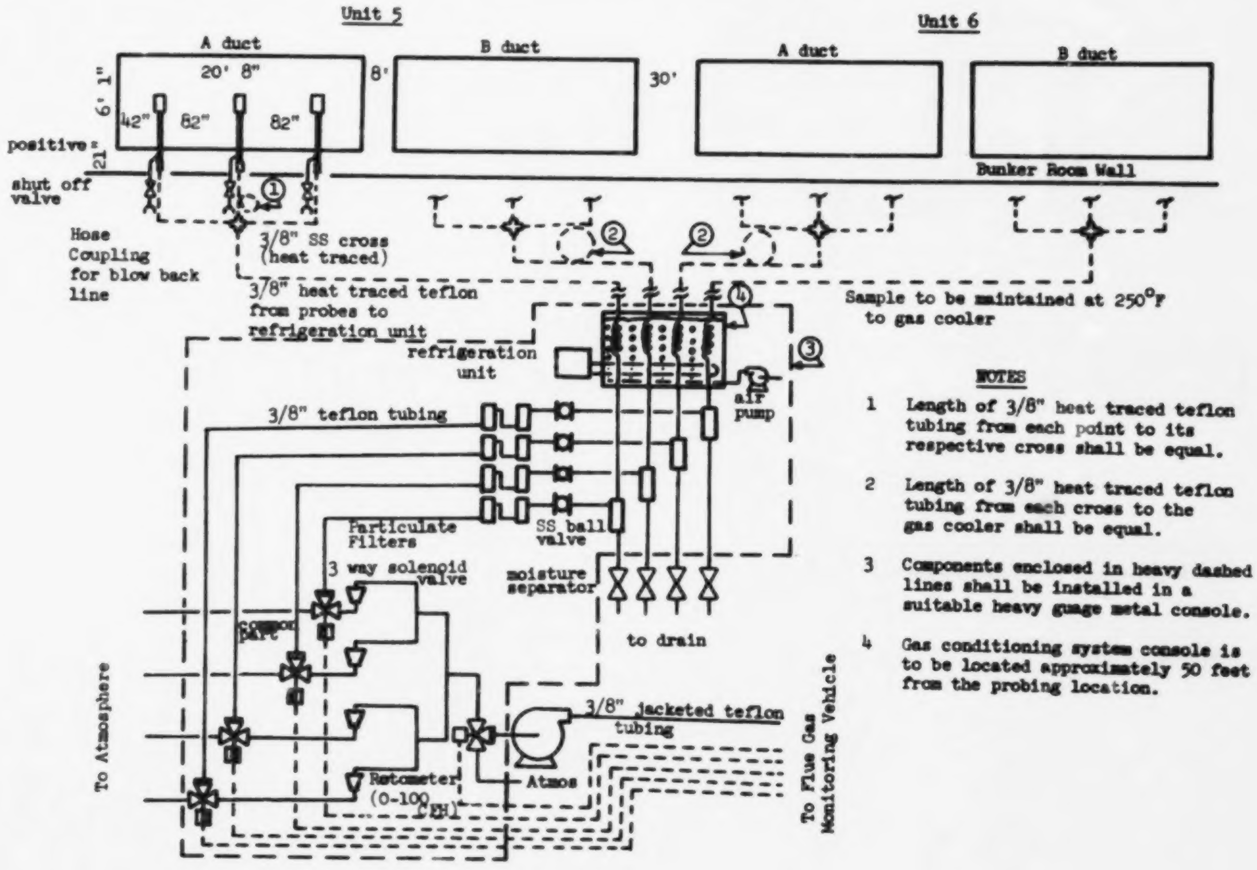
PROBE NO.	ELEMENT NO.	WEIGHT (GRAMS) BEFORE	WEIGHT (GRAMS) AFTER	% LOSS (GRAMS)	EXPOSURE TIME (T) (HOURS)	CORROSION RATE (MILS/YR)
2	19	122.9264	121.3812	1.26	358	54.5
	32	127.3860	126.3723	0.80	358	35.4
4	21	262.3952	254,9666	2,83	356	131.9

FIGURE 1

TVA's 125MW Widows Creek Unit 6 - Burner Configuration


ROW
1
2
3
4
PULVERIZER
A
B
C
D

FLUE GAS SAMPLING AND CONDITIONING SYSTEM


Unit 5
Unit 6
A duct
B duct
A duct
B duct
20' 8"
8'
30'
6' 1"
42"
82"
82"
positive
21
shut off valve
Bunker Room Wall
①
②
②
Hose Coupling for blow back line
3/8" SS cross (heat traced)
3/8" heat traced teflon from probes to refrigeration unit
④
Sample to be maintained at 250°F to gas cooler
③
refrigeration unit
air pump
3/8" teflon tubing
Particulate Filters
SS ball valve
3 way solenoid valve
moisture separator
common port
to drain
To Atmosphere
Rotometer (0-100 CFH)
Atmos
3/8" jacketed teflon tubing
To Flue Gas Monitoring Vehicle

NOTES

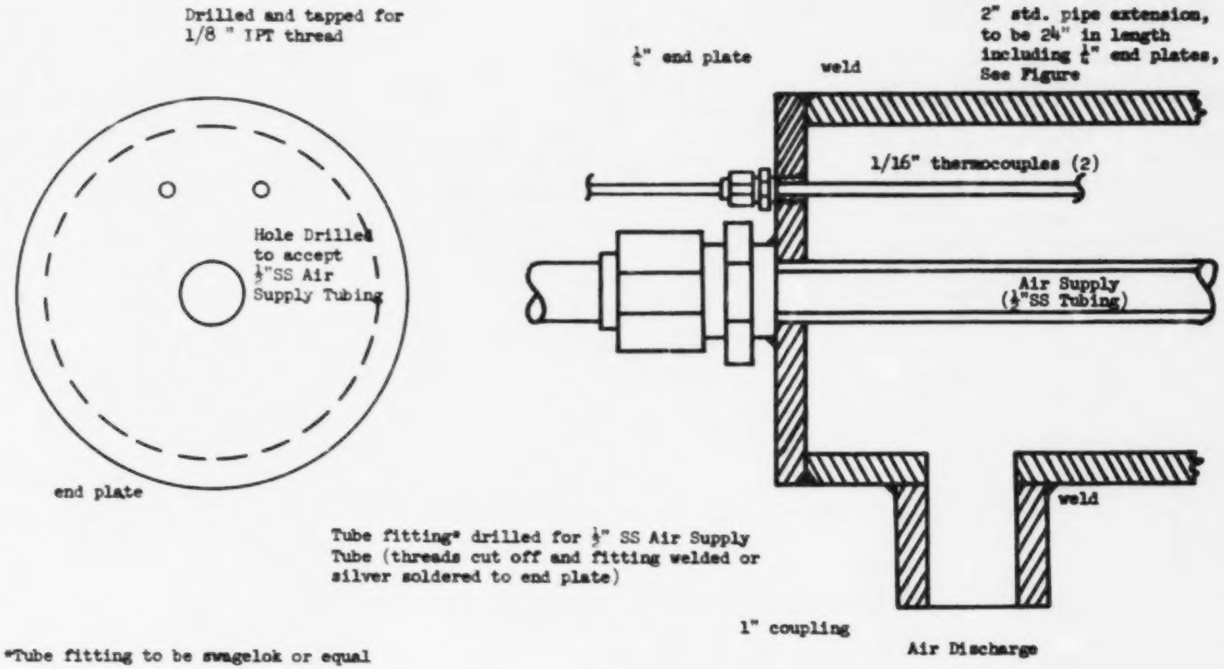
1 Length of 3/8" heat traced teflon tubing from each point to its respective cross shall be equal.

2 Length of 3/8" heat traced teflon tubing from each cross to the gas cooler shall be equal.

3 Components enclosed in heavy dashed lines shall be installed in a suitable heavy guage metal console.

4 Gas conditioning system console is to be located approximately 50 feet from the probing location.

CORROSION PROBE


Drilled and tapped for
1/8 " IPT thread
¼" end plate
weld
2" std. pipe extension,
to be 2¼" in length
including ¼" end plates,
See Figure
1/16" thermocouples (2)
Hole Drilled
to accept
½"SS Air
Supply Tubing
Air Supply
(¼"SS Tubing)
end plate
weld
Tube fitting* drilled for ½" SS Air Supply
Tube (threads cut off and fitting welded or
silver soldered to end plate)
1" coupling
Air Discharge

*Tube fitting to be swagelok or equal

CORROSION PROBE

Detail of Corrosion Coupon Assembly
(Inside of Furnace)

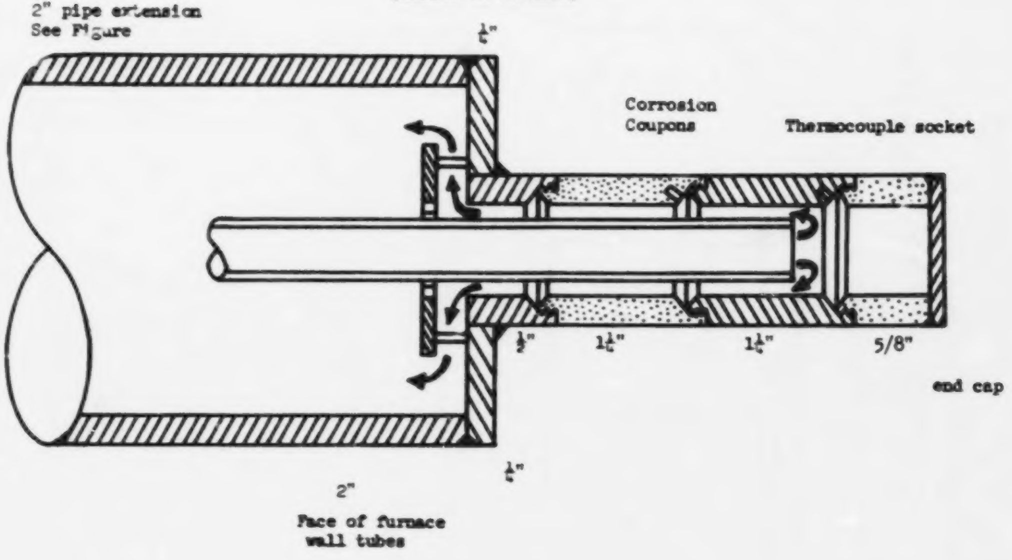
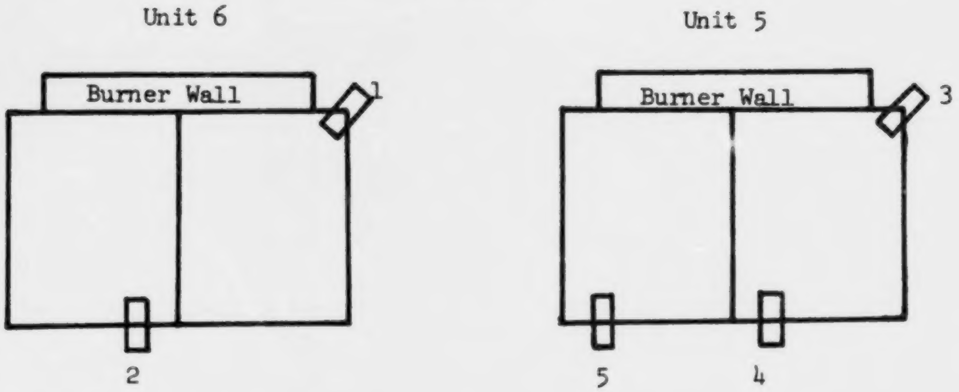

2" pipe extension
See Figure
¼"
Corrosion
Coupons
Thermocouple socket
½"
1¼"
1¼"
5/8"
end cap
¼"
2"
Face of furnace
wall tubes

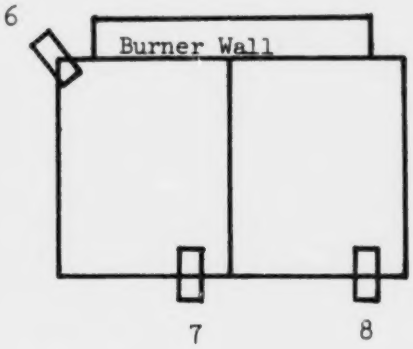
FIGURE 5

PROBE LOCATIONS


Unit 6
Burner Wall
1
2
Unit 5
Burner Wall
3
5
4

"C" Burner Elevation

"C" Burner Elevation

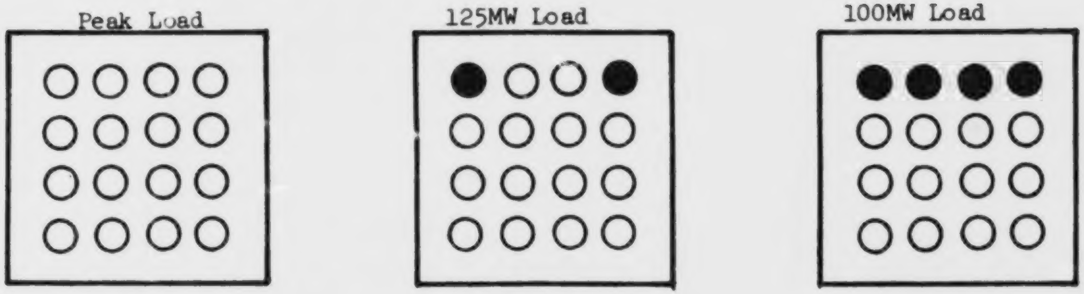

6
Burner Wall
7
8

"B" Burner Elevation

FIGURE 6

Biased Firing Test Conditions

For Long Term Corrosion Studies



Peak Load

125MW Load

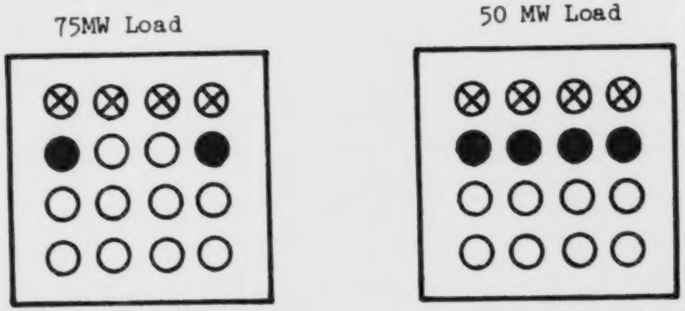
100MW Load

16-Burners in service Reduction of excess air until burners show a rapid change in CO. NO_x lowest as possible.

14-Burner configuration A_1, A_4 burners on air only. Reduce excess air until burners show a rapid change in CO. NO_x less than 500 ppm.

12-Burner configuration A_1, A_2, A_3, A_4 burners on air only NO_x less than or equal to 400 ppm. Reduce excess air until burners show a rapid change in CO.

FIGURE 6
Cont.



10-Burner configuration
A_1, A_2, A_3, A_4 burners off (coal and air)
B_1, B_4 burners on air only
NO_x less than 400 ppm

8-Burner configuration
A_1, A_2, A_3, A_4 burners off (coal and air)
B_1, B_2, B_3, B_4 on air only
NO_x less than or equal to 300ppm
A-forced draft and induced draft fans off

NOTES:
1) ○ - Burner on coal and air
2) ● - Burner on air only
3) ⊗ - Burner off (coal and air)
4) The 10 and 8 burner biased firing test configuration is not a normal operating condition at Widows Creek units 5 and 6.

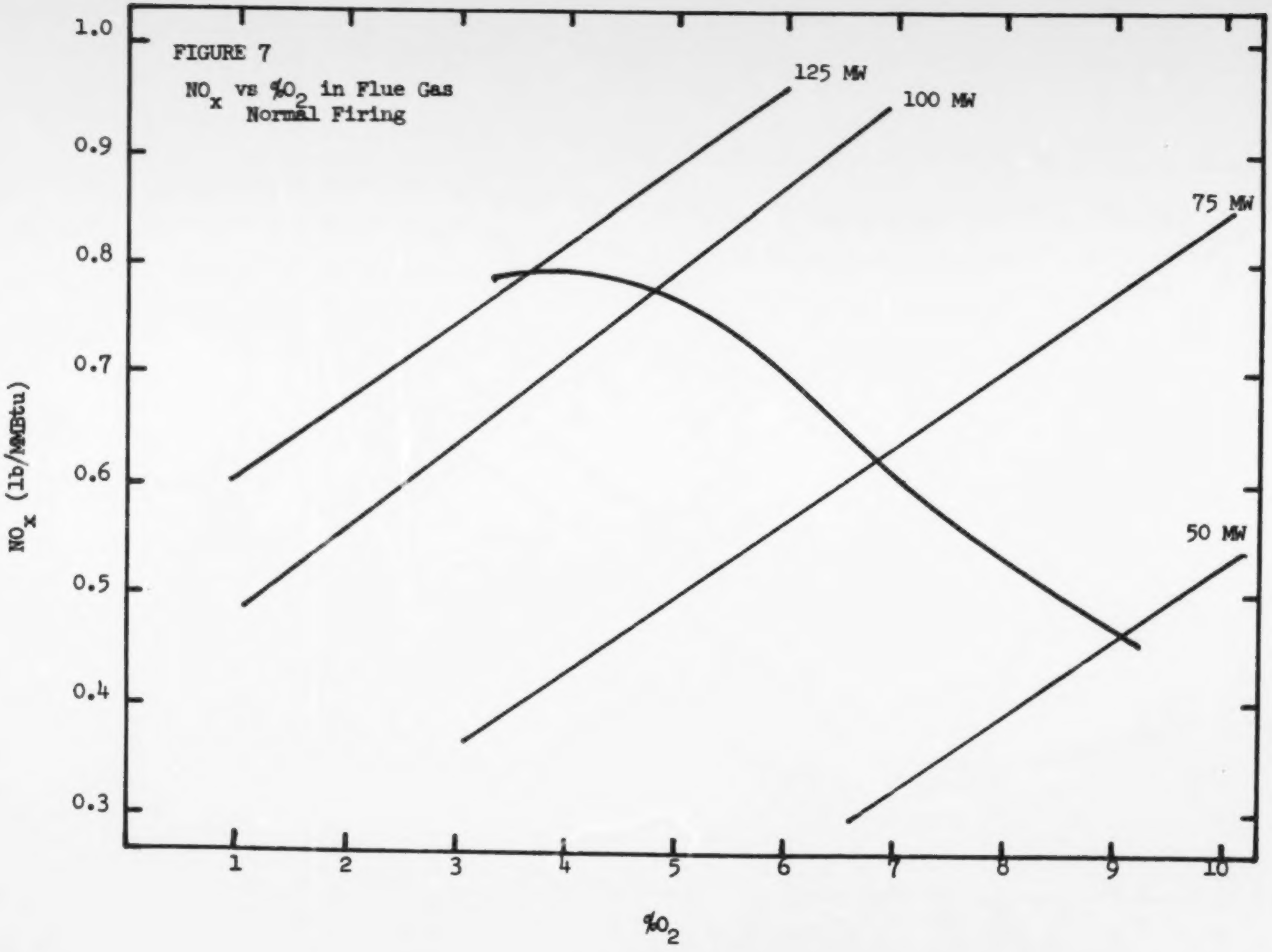


FIGURE 7

NO_x vs $\%O_2$ in Flue Gas
Normal Firing

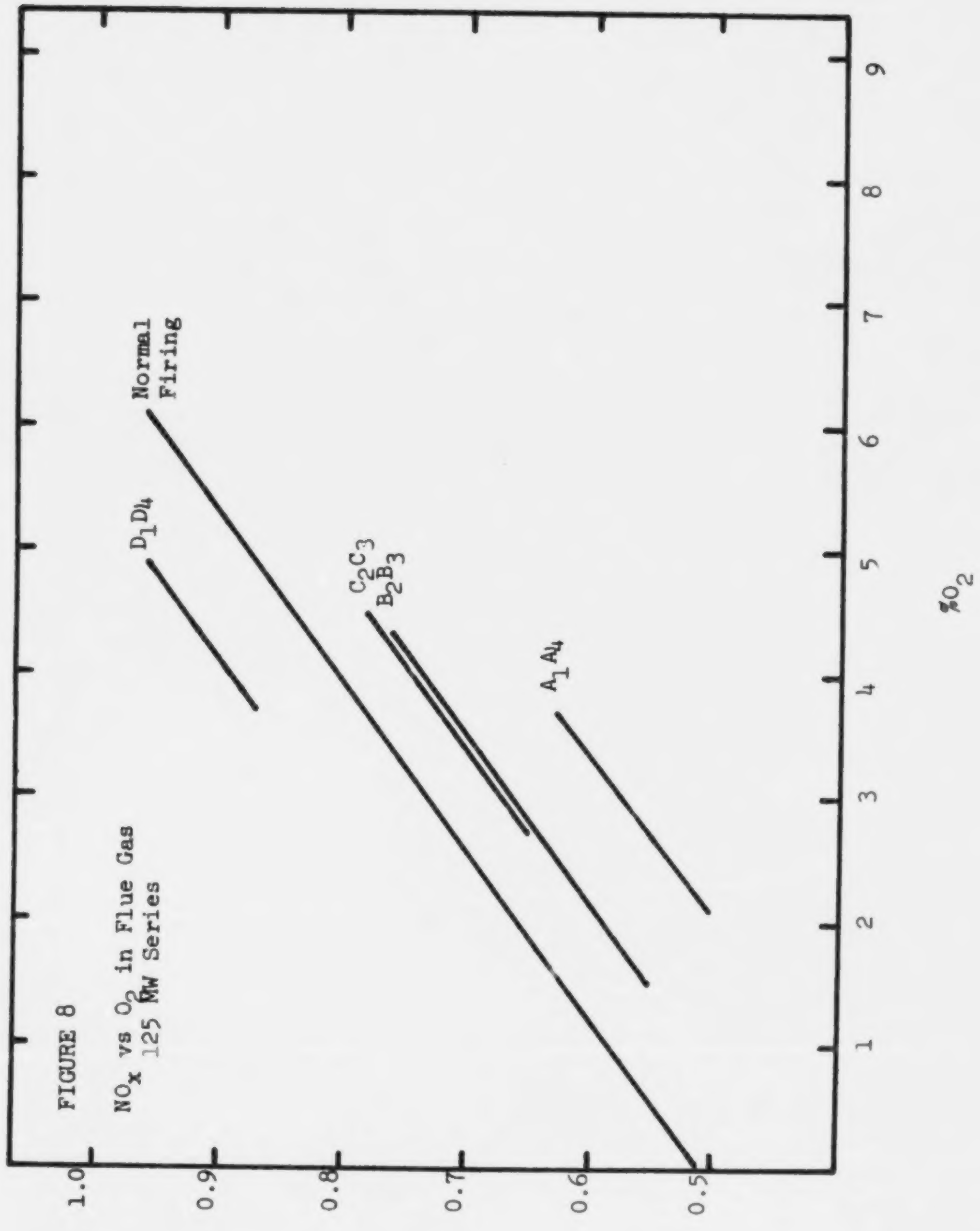


FIGURE 8

NO_x vs O_2 in Flue Gas
125 MW Series

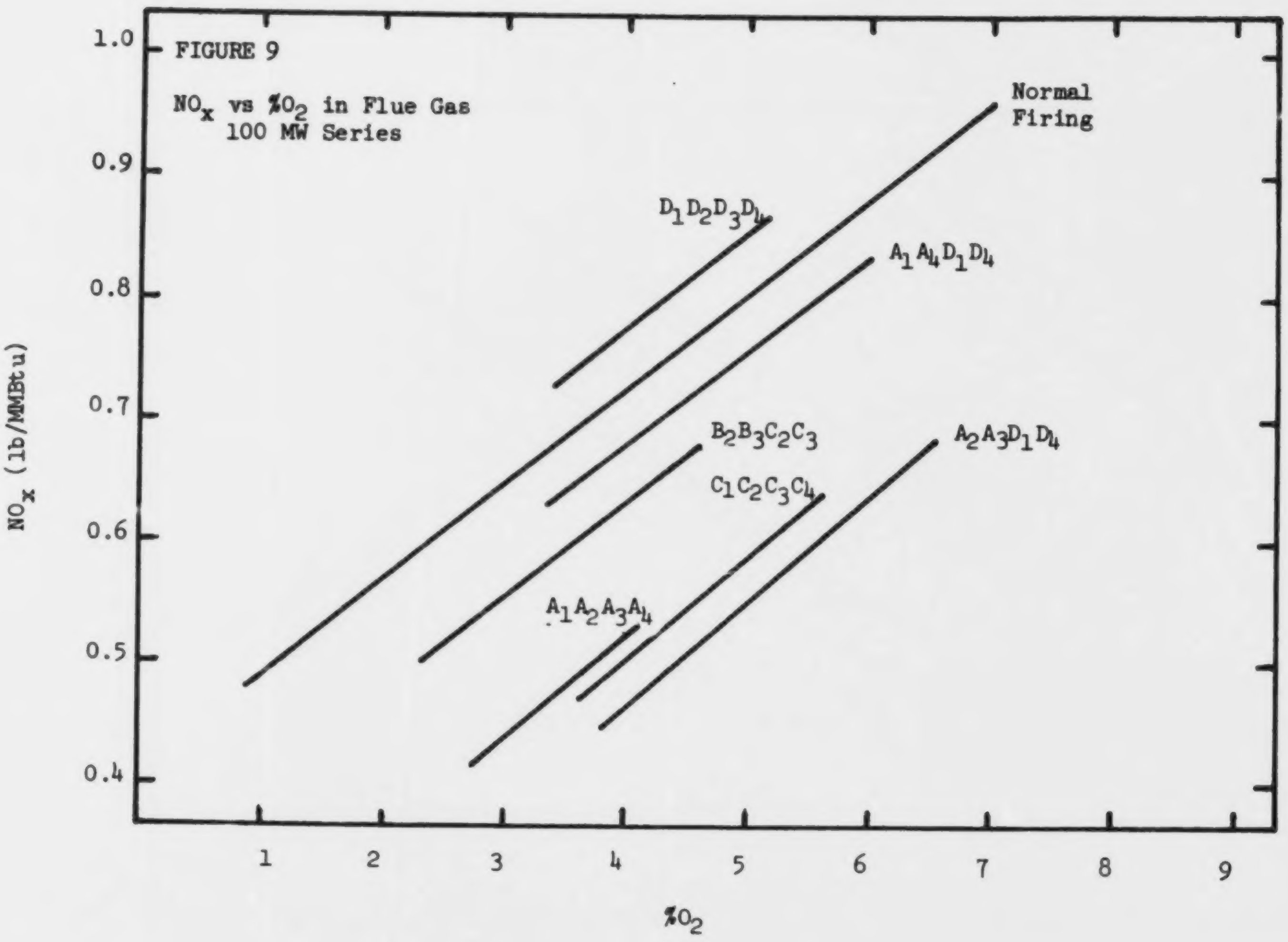


FIGURE 9

NO_x vs $\%O_2$ in Flue Gas
100 MW Series

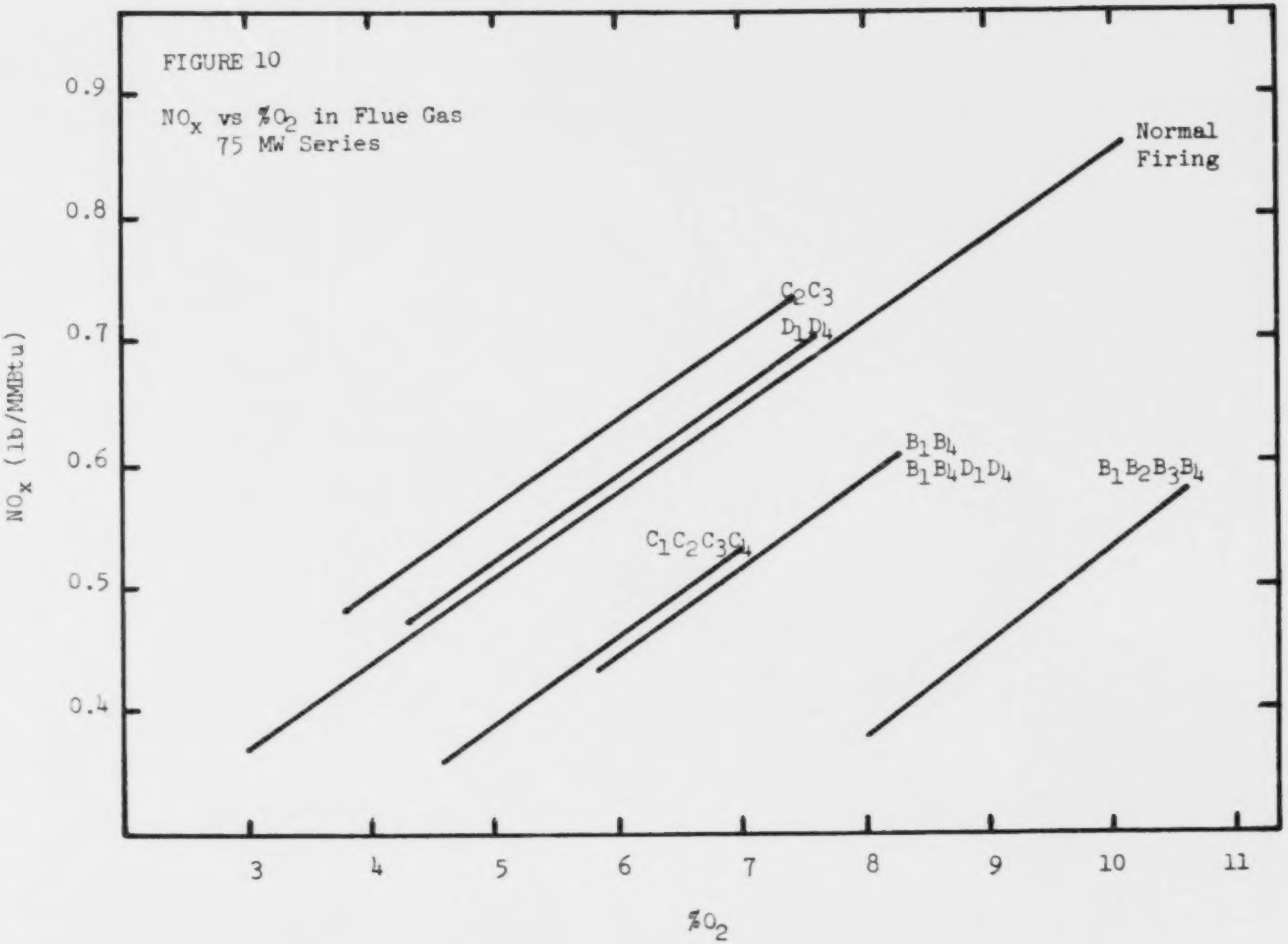


FIGURE 10

NO_x vs $\%O_2$ in Flue Gas
75 MW Series

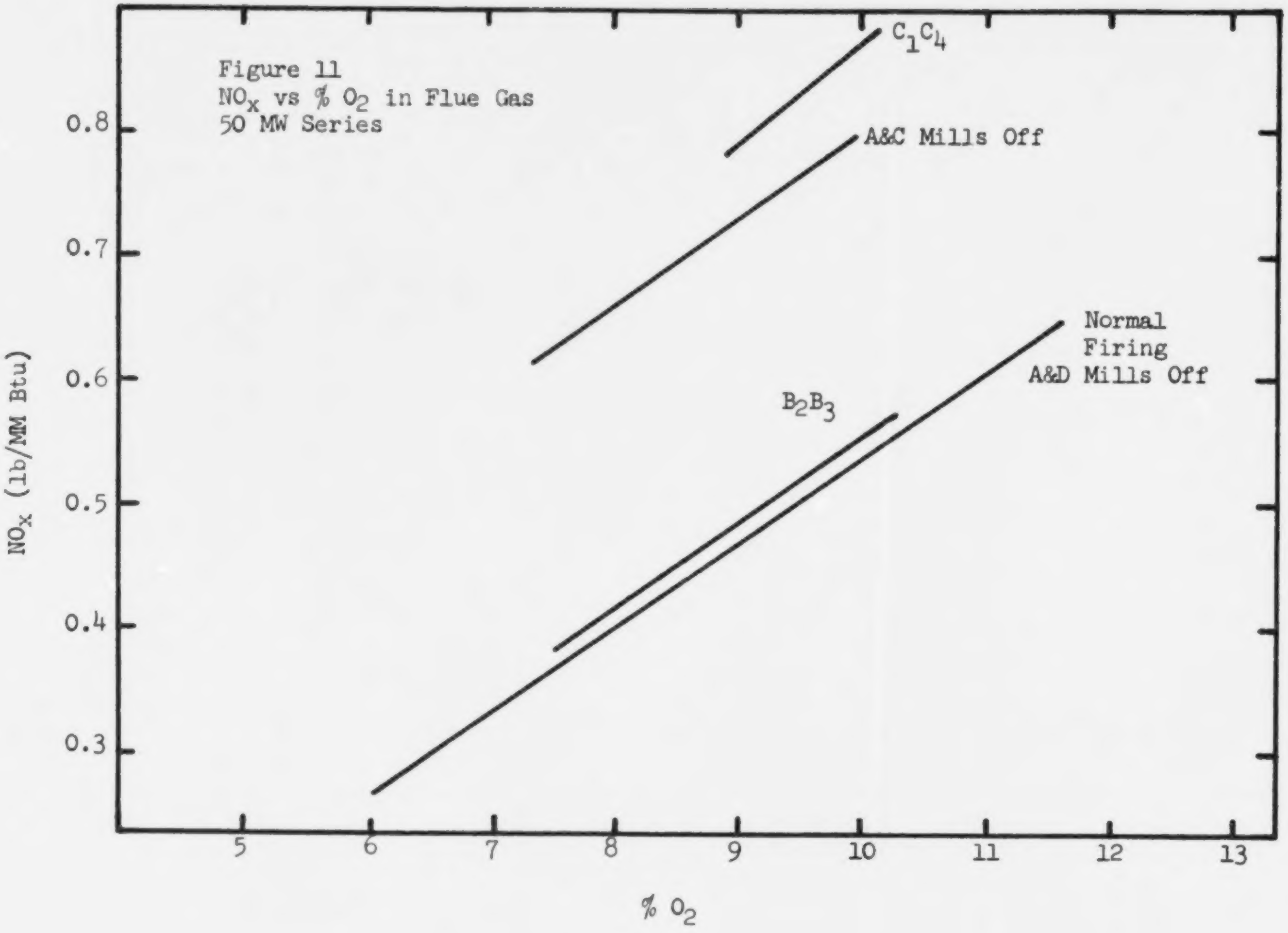
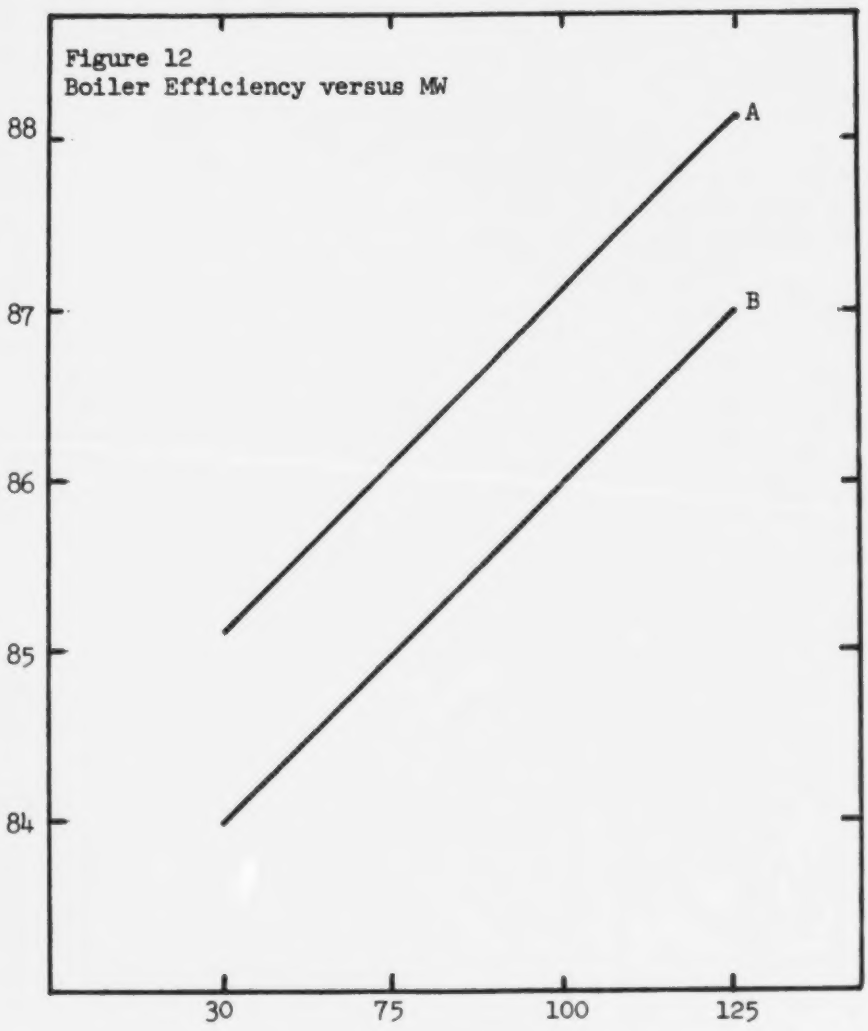


Figure 11
NO_x vs % O_2 in Flue Gas
50 MW Series



A - Normal Firing
B - Biased Firing

4:20 p.m.
Control of NO_x Formation in
Wall Coal-fired Boilers
Dr. Gerald A. Hollinden, Tennessee Valley Authority

Q: I tried to glance through your paper quickly I couldn't see it, it might be in there...where did you measure the particulate loading? Was it before the ESP, after the ESP, or where was it?

A: It was after the air pre-heater section.

Q: What was your particular collection device for that system?

A: It was a Research Appliance system mechanical collector.

Q: You made the statement that the carbon losses were increasing but there was no overall, there was no increase leaving the furnace. It had to be accounted for someplace.

A: No, I said no significant increase in particulates. The difference that we did notice was in the chemical content of the fly-ash as opposed to the quantity of the fly-ash.

Q: You are aware that Exxon tested boiler number six (Widow's Creek, No. 6) a couple of years ago and we obtained similar results on increased carbon on particulates. We evaluated that out on the effect on performance and there was no significant effect on performance or efficiency. You are also aware that we tested your same boiler.

A: I am not aware that you did any ignition loss tests on the particulate; I may be wrong.

Q: We did check the carbon and calculate the efficiency by the same method you did. And we found even under those conditions, where we had an increase in carbon, that there was no appreciable difference in efficiency. Remember, we reduced the excess air and we had a net gain in efficiency from that standpoint. So the two balance each other out. That was in the prior work.

A: You know we shouldn't mislead the audience. We would have to compare the excess air levels. I have already mentioned that we dropped pretty low (excess air), especially at 125 megawatts, and I don't think we would do that again. I don't really remember 2 years ago what we ran for excess air levels. I don't think it was as low as what we did in this program.

Q: Tomorrow I will present some other data on your same boiler and in that case we had a decrease in carbon loss on low NO_x firing on the same boiler. Now, I gather from your data you are saying, in every case, low NO_x firing increased the carbon loss. Is that true?

A: That is true. I am saying that with the four low NO_x conditions that we selected for 50, 75, 100 and 125 megawatts, compared to normal firing at those four loads, we did have a reduction in boiler efficiency. We did not obtain particulate data for all 47 tests.

Q: We are also going to present some data on corrosion based on corrosion probes taken on your boiler #5 and boiler #6. Our data show that there is no significant difference in corrosion, by corrosion probes.

A: It is very important, as I stated earlier, where you put the corrosion probes, since the probes are just an indicator of corrosion. In one case under normal firing conditions we got an equivalent 8 mils loss per year on a particular probe and under the same conditions several weeks later got 50 mils loss per year. Obviously there was not a seven-fold increase in corrosion for the normal firing case over that period of time. So I don't hold much credence from a quantitative standpoint in our corrosion probe information except that it was strange that we always got more corrosion or more loss of the coupons in the stage-fired unit as compared to the normal firing. And that is really my whole point. The important issue is that more information is needed on the actual tube-wall measurements. That will give you your final answer.

Q: What I would like to know is whether or not the O_2 levels or excess air levels at the corrosion probes were determined when you saw the increased losses.

A: No, they were not. We didn't have any sample withdrawn in the furnace area itself.

Q: Can you give us some idea what your overall excess air was, and what your burner stoichiometry was at the conditions where you saw the dramatic reduction?

A: At 50 megawatts and 75 megawatts the O_2 level was somewhere between 6 and 9%. We weren't even near reducing condtions in the burner region. However, at 125 megawatts, where we were operating under biased firing conditions at 3% O_2 we were substoichiometric in the burner region. I don't know what all of them were, but at 125 megawatts we got down to about .85 to .9.

Q: And this is where your corrosion data was taken that you showed?

A: Yes. Again, the corrosion data for the coupons were only done for the four selected tests. They weren't done for all of them. However, the boiler corrosion tube data was done over the entire program.

Q: Gerry, did you note any difference in furnace performance under bias-firing conditions?

A: No, sir.

Q: No increases in spray-flows and things like that?

A: No, every once in a while we saw some soot fly across from one region to the other.

[Comment by Symposium Vice-Chairman:]
I think it is important to point out, as you have alrady said, some of the test data is not in yet. There are still some questions remaining on the results of this program. Even assuming that it all pans out the way it looks, I think it is important to point out that this data was taken on one unit; it is not necessarily typical of all boilers, especially different designs, and a lot of work in this area still needs to be done before conclusions can be drawn.

Q: On the calculations of efficiency, was it done on a heat rate basis, Btu's per kilowatt hour, or did you calculate it on another basis?

A: No. It was merely a boiler efficiency calculation.

[Comment by Moderator:]

Sometimes on a heat rate basis, it may not change. In other words, it takes the same number of Btu's to generate the same KWH regardless of your conditions. And it is my understanding that some boiler manufacturers (I may get jumped on for this by some of the people who are manufacturing wall-fired units), are aware of the potential for corrosion, especially on the wall, on the side walls, and note that on this unit we had apparent corrosion on the division wall and on a side wall. Some manufacturers are building in a curtain air concept wherein there is some bleed air that is brought down the side wall to sort of compensate for this.

THE EFFECT OF ADDITIVES IN REDUCING PARTICULATE EMISSIONS FROM RESIDUAL OIL COMBUSTION

By

R. D. Giammar, H. H. Krause, A. E. Weller, and D. W. Locklin

BATTELLE
Columbus Laboratories

Columbus, Ohio

Preceding page blank

THE EFFECT OF ADDITIVES IN REDUCING PARTICULATE EMISSIONS FROM RESIDUAL OIL COMBUSTION

by

R. D. Giammar, H. H. Krause, and A. E. Weller

ABSTRACT

In this study, the effectiveness of proprietary additives and pure compounds in reducing particulate emissions was evaluated in a 50-hp (500 kW) oil-fired packaged boiler. It was observed that additives containing certain alkaline-earth and transition metals in concentrations in the range of 20 ppm to 50 ppm in the oil were effective in reducing carbon particulate by as much as 90 percent. These additives were also observed to be effective in reducing smoke and polycyclic organic matter. Explanations are offered suggesting possible additive effects on the combustion mechanism that could account for differences in performances of the various additives in achieving particulate emission reduction.

THE EFFECT OF ADDITIVES IN REDUCING PARTICULATE EMISSIONS FROM RESIDUAL OIL COMUBSTION

by

R. D. Giammar, H. H. Krause, and A. E. Weller

INTRODUCTION

The use of small amounts of fuel additives as a means of improving the performance of fossil-fuel boilers has been of recurring interest for many years. Trials with various fuel additives have had different objectives, depending on the type of fuel used and the era in which the trials were conducted. Earlier additive trials and investigations were aimed at reducing the deposition of soot and ash on heat-transfer surfaces and minimizing the corrosion that resulted from the accumulation of these deposits and from their interactions with the flue gases. Recently, the use of additives has been emphasized as a possible method of reducing air pollutant emissions--mainly visible smoke and particulate--although some claims have been made of additives reducing emissions of sulfur oxides and nitrogen oxides.

Although a substantial level of effort has been devoted by various organizations to the development of additives to reduce air pollution emissions, the effectiveness of some of these additives has been in question because of the lack of consistent results in both experimental laboratory investigations and in actual commercial usage. These inconsistencies, in part, could be attributed to differences in combustion equipment, operation, and maintenance; fuel type and composition; and perhaps, most importantly, evaluation methodology.

Thus, while qualitative observations and commercial claims for the effectiveness of additives are numerous, relatively few quantitative data are available from experimental investigations in which boiler operating conditions were well-defined and in which emissions were accurately measured. Consequently, there are few scientific data to support an assessment of how, and under what conditions, additives work.

This paper discusses a portion of an ongoing research program for the U.S. Environmental Protection Agency* to systematically evaluate the effectiveness of additives for reducing combustion-generated air pollutant emissions, especially particulate, from an oil-fired continuous combustion system. This program is unique in that an extensive and well-documented program was conducted to evaluate a large number of proprietary additives and pure compounds under controlled conditions in a single unit--a commercial 50-hp (500 kW) Scotch firetube boiler firing residual oil. This work is an extension of the work of G. B. Martin, et al., who systematically evaluated about 300 additives for reducing emissions from a distillate oil-fired residential burner(1)*.

---

* EPA Contract No. 68-02-0262, "The Effectiveness of Fuel Additives in Reducing Emissions from Oil-Fired Continuous Combustion".

In general, most proprietary additives have not been found to be effective in reducing air pollution emissions(1). However, some additives have been found to be effective in substantially reducing smoke and particulate(1).

REVIEW OF EXPERIMENTAL ADDITIVE INVESTIGATIONS

To guide the selection of additives for this program, the literature pertaining to experimental studies of combustion additives was reviewed**. Previous investigators have used a wide variety of organic, organo-metallic, and inorganic compounds in efforts to reduce the amounts of pollutants formed during combustion, or to convert the pollutants into easily removable solids.

The greatest amount of effort in additive development has been devoted to particulate emissions. This emphasis has been the result of the almost universal recognition of smoke as an undesirable emission over a period of many years. For obtaining reduction in particulate formation in fuel-oil combustion processes, experimental evidence indicated that compounds of the transition metals, manganese, iron, nickel, and cobalt, could be effective(2). The alkaline earth metals, barium and calcium, also gave evidence of useful activity(3,4). The best results were obtained with organometallic derivatives of these metals. The organic portion of the molecule provides the needed solubility in oil and also influenced the stability and volatility of the additive molecule.

---

* Numbers in brackets designate References at the end of the paper

** This state-of-the-art review was a part of the program on EPA Contract No. 28-02-0262 and will be submitted as part of the final report.

Only a few investigations have examined the effect of additives on potential carcinogenic materials in the particulate emissions, but this aspect is presently receiving a significant amount of attention. Such potential carcinogenic agents are found primarily in the polycyclic organic material (POM) that forms during the combustion of the fuel(5,6). Most of the early research was done with gas flames or light fuels such as distillate oil. The additives which were reported as effective in reducing the POM emissions included organic compounds such as nitroparaffins and peroxides(7), as well as organo-metallic compounds of manganese and iron(8). Although the physical state of POM and the carbonaceous portion of the particulate is different, their probable common origin and chemical reactivity suggest that an additive effective for one would have some effect on the other. This result was generally observed in the earlier diesel engine studies, and where both types of emissions were measured, the POM usually was reduced to a greater extent than was the particulate(7).

The U.S. Environmental Protection Agency has conducted two comprehensive experimental programs that have contributed quantitative information on the effects of fuel-oil additives in reducing pollutant emissions. One program involved tests of numerous commercial additives used with distillate heating oil in a residential oil burner(1). In general, the additives were found to have a minor effect compared to the opportunity for emission control by proper adjustment and operation of the burner. However, the additives containing manganese, iron, or cobalt did reduce the particulate emissions. A few organic formulations containing no metals gave moderate reductions in particulates, but the concentrations of the additives required were too high to be practical. No changes were observed in the amounts of nitrogen oxides or sulfur oxides in the emissions with any of the additives.

The second EPA program was an investigation of the effectiveness of several propriatary fuel-oil additives in reducing sulfur oxide emissions when firing residual oil in a commercial boiler(9). No effects of the additives were found for sulfur oxide emissions or for nitrogen oxides.

The experience of the EPA investigators with the inefficiency of additives for reducing the nitrogen oxides or sulfur dioxide in the emissions verified the generally negative results reported by the earlier studies. Only in the case of sulfur trioxide, which is present to the extent of 25 to 30 ppm in the flue gases, has an additive effectiveness been demonstrated. Chemicals which form basic oxides such as magnesium, calcium, and zinc have reduced sulfur trioxide levels substantially(10).

A further consideration in the use of additives is their effect on the combustion equipment and emissions contributed by the additives. Because additives often contain high concentrations of solids or inerts, including potentially corrosive salts or toxic metals, the use of these additives in some combustion systems can be detrimental. Many additives contain metals that would be emitted in the flue gas and for which the potential environment hazards are not well defined.

EXPERIMENTAL PROGRAM

Commercially available additives and other materials selected as a result of the previous considerations were experimentally evaluated with fuel oil in a 50-hp (500 kW) firetube, packaged Scotch boiler capable of firing natural gas, distillate oil, and residual oil at rates up to 2 million Btu/hr and generating up to 1500 lb/hr (680 kg/hr) of steam at 15 psig (103 kN/m^2). Combustion air was metered with a thin-plate orifice, distillate oil flow with a rotameter, and residual fuel oil flow was determined from beam-scale readings. Fuel was supplied to the burner at a fixed rate by a variable-speed, positive-displacement gear pump. For residual oil requiring preheating, controllers were used to provide a constant fuel temperature at the pump inlet and burner nozzle.

The combustion gases were vented from the boiler through a 12-in (0.305 m) diameter insulated stack. A special sampling platform permitted sampling in a straight section of stack, 15 ft (4.6 m) above the boiler outlet. Figure 1 shows the overall experimental facility.

Analytical Procedures

Particulate and POM sampling and analytical procedures (modified EPA Method 5 train with an adsorbent column) have been described by Jones and Giammar(11). Gaseous emissions were determined by: paramagnetic analysis for oxygen; flame ionization detection for unburned hydrocarbons; nondispersive infrared for carbon monoxide, carbon dioxide, and nitrogen oxide; and a dry electrochemical analyzer for sulfur dioxide. Smoke emissions were determined with a Bacharach smoke tester according to the ASTM filter-paper method for smoke measurements(12).

Fuel

To provide a uniform reference fuel, 6000 gallons (22.7 m^3) of a residual fuel oil were obtained that consisted of: 87.5 percent C, 11.1 percent H, 0.31 percent N, 0.95 percent S, and less than 150 ppm trace metals. API gravity was approximately 15°. The distillate oil used was a typical No. 2 heating oil, with 86.4 percent C, 13.6 percent H, and less than 0.1 percent S. An additional 6000 gallons (22.7 m^3) of a 2 percent sulfur residual oil was also procured and additives are currently being evaluated with this oil.

Selection of Additives

Fuel additives have been used as a means of accomplishing a number of functions that can be distinguished as occurring before, during, or after the combustion process. For the purposes of this investigation, only additives that were intended to improve combustion and thus reduce emissions, were considered. However, it is recognized that fuel handling and postflame treatment additives can in some circumstances prove the overall performance of a combustion system, especially in marginal cases, by keeping nozzle or heat transfer surfaces clean.

To categorize these "combustion improver" additives, the following three classes were defined:

- Organo-metallic
- Organic
- Inorganic.

Table 1 categorizes the additives used in this study according to defined classes and subclasses. Inorganic additives were not evaluated because of their insolubility in oil. Selection of these additives was based on a state-of-the-art review of additive technology and on theoretical considerations of the mechanism of pollutant formation and possible modes of additive action.

Concentrations

Concentrations for the proprietary additives were based upon the manufacturer's recommendations or the results of an earlier EPA study$^{(1)}$. For pure compounds, concentrations were based on approximately 27 ppm of metal in the oil (0.1 g metal/gal of fuel oil).

Procedure

To ensure a valid and controlled evaluation of each additive, procedures were developed to minimize operational variations over the entire period of experimentation (approximately 1.5 hr) and to provide several measurements for evaluation purposes.

For each additive evaluation run, the reference fuel oil was fired at a constant, continuous rate in the boiler facility to establish a baseline operating performance over a range of air/fuel ratios. Gaseous and smoke emission data were obtained over this entire range, while a filterable particulate emission[*] was determined at one selected air/fuel ratio. The additive containing fuel was fired at the same firing rate over the same range of air/fuel ratios to generate a boiler performance curve with the additive. A particulate sample was also obtained at the same air/fuel ratio as for the reference oil run. Thus, the effectiveness of each additive could be determined by comparing the smoke and gaseous characteristic curves and the particulate loadings with and without additive for runs made on the same day. (Except as noted, all data reported in this paper were obtained at steady state.)

Particulate consists of two basic components: (1) an ash component originating with the fuel, and (2) a carbon component resulting from incomplete combustion. For combustion at a constant air/fuel ratio, the ash loading in the products of combustion should be constant assuming no accumulation on the boiler surfaces; the carbon loading could vary depending on the completeness of combustion. To minimize the variation in ash loading, all particulate measurements were made at the same air/fuel ratio corresponding to 12.8 percent CO_2 (about 20 percent excess air). A baseline firing rate of 80 lb/hr (36 kg/hr) was selected to correspond to a commonly used boiler load of 80 percent.

---

[*] Probe and filter catch only.

SUMMARY OF RESULTS

Although additives were evaluated with both distillate and residual fuel oils, this discussion will be limited to the residual oil runs, because steady-state firing of distillate oil in the 50-hp (500 kW) boiler did not generate appreciable quantities of carbon particulate at normal air/fuel ratios (over 8 percent excess air). Thus, a valid measure of the effectiveness of additives firing with distillate oil could not be made. In fact, for those additives containing metals, particulate loadings were observed to be increased by the use of additives with distillate oil.

Table 2 summarizes the results of the additive evaluation runs firing the 1 percent sulfur residual fuel oil at 12.8 percent CO_2. As indicated in portions (d) and (e) of Table 2, several runs were conducted at different firing rates and one run was conducted with cyclic boiler operation so that other modes of boiler operation could be considered. The additive concentrations or dosages are either designated as ppm metal in the fuel oil for those additives containing metal even in trace quantities, or by volume percent for the pure organic compounds. As for the naphthenic and 2-ethyl hexoic acids, the volume percentages were selected to give the same volumes as used for the barium naphthenate and barium 2-ethyl hexoic runs, while the volume percentage for toluene was selected to give the same volume percentage of the proprietary hydrocarbon additives. The results of the evaluation runs with the 2 percent sulfur residual oil are incomplete at this time. However, cursory analysis of the data indicate approximately the same level of additive effectiveness with the 2 percent sulfur residual as with the one percent residual oil.

Statistical Considerations

Table 2 includes the particulate loadings for both the daily baseline run and the additive run made that same day. These daily baseline runs were used as a measure of the variation in particulate emissions. As discussed earlier, the ash loading for every run should be nearly the same and, accordingly, and deviation in the baseline particulate loadings from day-to-day would have to be attributed to the deviations in the carbon portion of the particulate loading . The standard deviation of the particulate loadings for the baseline runs of Runs 6 through 31* is 10 mg/sm^3, less than 10 percent of the arithmetic mean of 104 mg/sm^3 of these runs. Consequently, each additive was evaluated by comparing the particulate loading of the specific additive run with the arithmetic mean of the particulate loadings of all daily baseline runs. This method minimizes the effect of random variations in the particulate emissions but may bias the results somewhat in that additives with low (or high) daily baseline particulate loadings (assuming these observed loadings are "real" rather than instrument or measurement errors) appear more effective (less effective) than if the particulate loading of the additive run had been compared with the specific daily baseline loading. However, regardless of which method of comparison is used, the conclusions would be similar.

Figure 2 graphically shows the effectiveness of the proprietary, organo-metallic, and organic additives in reducing filterable particulate. The arithmetic means and the estimated ash component of the particulate loading are shown. The data indicate, in general, those additives containing certain alkaline-earth or transition metals in concentrations of about 20 to 50 ppm in the oil significantly reduced particulate emissions. The use and effectiveness of these additives at higher concentrations is somewhat questionable. It has been observed that even though carbon burnout can be further promoted at the higher concentrations, the net reduction in particulate is not substantial because of the additional particulate from the metallic inert contained in the additive.

---

* The level of 100 mg/m^3 was determined from the standard error of the mean of the baseline runs.

Also shown in Figure 2 is a line located at two standard deviations below the baseline average. This standard deviation is based on the individual baseline measurements and is regarded as equally valid for the particulate measurements with additives. Although the use of two standard deviations strictly requires the assumption of normality to correspond to a 95 percent confidence level, it is used here in a broad sense to indicate a reasonably high, but unknown, confidence level. Those particulate measurements for additives falling below the line are concluded to be statistically significant (not due to chance) at this reasonably high confidence level. Those additive runs falling above this level (84 mg/m^3) but below 100 mg/m^3* suggest that these additives are effective, but more experimental data are required to establish the level of statistical significance.

In addition, the measurements indicate that some additives are more effective in reducing particulate than others. However, by assuming that a standard deviation of 10 mg/m^3 also applies to the additives runs, a statistical treatment of the data would indicate that the effective additives are not statistically distinguishable.

Effect of Carbon Particulate

For the baseline boiler operating condition of 80 lb/hr (36 kg/hr) at 12.8 percent CO_2, the average carbon content of the filterable particulate was observed to be about 50 percent for a corresponding filterable particulate loading of 104 mg/sm^3. Accordingly, additives can only reduce particulate loadings by about 50 percent to about 50 mg/sm^3 which represents the ash component associated with the inerts of the fuel oil, unless the use of additives caused a larger portion of the particulate to remain within the combustion system (this would probably be undesirable as it would foul heat transfer surfaces).

---

* The level of 100 mg/m^3 was determined from the standard error of the mean of the baseline runs.

This observation that particulate loading can be reduced to about 50 mg/sm^3 is verified by the results of Runs 13, 14, 32, 33, 34, and 35 in which the boiler was fired at 5 boiler loads. Figure 3 shows the particulate loading generated by the boiler operated at each of 5 loads with and without one additive. For the baseline runs, particulate loadings were higher at the 100 percent load (Run 32) and the 35 percent load (Run 35) than at the 80 percent load (Runs 13 and 14), 65 percent load (Run 33), and 55 percent load (Run 34), but with the use of barium naphthenate, particulate loadings were reduced to about the same level of approximately 55 mg/sm^3, regardless of load. This particulate loading is about 10 percent higher than the anticipated ash level when firing the referenced fuel alone and can be attributed to the increase in metallic inert of the oil by addition of the barium naphthenate. Analysis of the particulate loadings of these runs (except Run 32) indicated that over 85 percent of the particulate was ash.

Additive Type and Concentration

The data obtained here indicate that some additives containing metals substantially reduced particulate emission. These additives were used in concentrations corresponding to the addition of between 20 ppm and 50 ppm of metal to the fuel oil. Proprietary additives considered organic with some trace metals also were shown to be effective at concentrations that corresponded to the addition of at least 15 ppm of metal to the fuel oil. As in the case of the additive "Formula LSD", these concentrations were significantly higher than those recommended by the manufacturer.

In general, the organo-metallic compounds listed in Table 2 were effective in reducing particulate except for two additives in the subclass cyclopentadienes (CI-2 and PD 1654, a ferrocene derivative) and zinc naphthenate. The proprietary additives (CI-2, Runs 4 and 20) and PD 1654 (Run 5), although observed to be effective in reducing particulate in other types of combustion systems firing distillate oil(1), were found to be ineffective in the 50-hp (500 kW) boiler firing residual oil; their ineffectiveness could be attributed to the type of bonding structure of these compounds (for PD 1654, the additive concentration used was that recommended by the manufacturer rather than one based upon a 27 ppm metal in the oil). The data indicate that the most effective agents are compounds of the alkaline-earth metals (barium and calcium) and the transition metals (manganese, iron, and cobalt).

Zinc, an element just beyond the above transition metals, was found to be an effective additive.

Some of the pure organic additives considered appeared effective in reducing particulate emissions. However, these additives had to be used at impractically high concentrations to be marginally effective and, therefore, could not be considered as a viable pollution control method.

Effect on POM

POM (polycyclic organic matter) measurements were made on a limited number of additive runs. These measurements included both total POM and species quantification for over 15 compounds (the majority of which are carcinogenic) as listed by the National Academy of Science(6). In general, additives that were effective in reducing particulate appear to be effective in reducing POM. Even if more data were available, it is improbable that any specific relation between additives and POM reduction could be made. It is believed that subtle changes in the combustion process that cannot be detected by the gross measurements of stack gas analysis have a significant effect on the formation of POM that would tend to mask an additive effect, especially considering that POM loadings were observed to be less than 10 $\mu g/sm^3$ for continuous steady-state combustion. For these relatively small POM loadings, over 99 percent of the POM found was considered innocuous.

POM measurements were also made during the cyclic operation of the boiler in Run 36. Although this size range of boiler would not be operated in an on-off cycle, but rather modulated to meet load, it was felt that some useful data could be obtained by operating the boiler for a 15-minute on/5-minute off cycle. As noted in Table 2, particulate loadings increased by a factor of two for both the baseline run and the barium naphthenate additive. However, POM levels of the baseline run increased by over two orders of magnitude (920 $\mu g/sm^3$) above the steady-state runs. For this run the additive was significantly effective in reducing POM (to 120 $\mu g/sm^3$) although the POM emissions still were much higher than for steady-state runs. This observation agrees with that of an early investigation in which it appeared that POM was reduced to greater extent than particulate by use of an additive(4). At the higher POM loadings, several compounds considered carcinogenic were found in appreciable quantities.

Effect on Smoke

As a measure of the effectiveness of additives in reducing particulate over a range of air/fuel ratios, Bacharach smoke measurements were made at about six excess air levels for every daily baseline run and every additive run. Figure 4 shows the effect of cobalt naphthenate (Run 7) and barium naphthenate (Run 13) on smoke reduction. In general, the relation between Bacharach smoke and CO_2 for the daily baseline runs as shown by the curve in Figure 4 remained constant from day to day as would be expected from the small variations in particulate loadings of these runs. Accordingly, the effectiveness of the additive could semiquantitatively be evaluated by comparing the smoke characteristic curves with and without the additive. The relative differences of these curves could be related to the relative differences in particulate loadings at 12.8 percent CO_2. From Table 2, for Run 7, the ratio of the particulate loading with and without additive was 0.71 and was 0.46 for Run 13, at a CO_2 level of 12.8 percent.

Effect on Efficiency

Figure 4 is a plot of stack-gas temperature as a function of time for 3 long-term (60 hours) runs with the 2 percent sulfur residual oil. Barium naphthenate was used at two boiler operating conditions; one condition matched the excess air level of the baseline run while the other condition matched the smoke density* of the baseline run.

The results of these runs are somewhat inconclusive because for the relatively short duration of these runs, it is difficult to predict the stack-gas temperature for an extended period of time (such as several months). It appears that the slope of the baseline curve is leveling off after 70 hours, and it is possible that by projecting the curves of all three runs, the curves would intersect. In all likelihood, however, the slopes of the additive runs should also level off and not intersect with the slope of the baseline run.

However, by assuming that the time-rate-of-change of the stack-gas temperature (the slope of the curves) of all three runs is the same after 60 hours, the effectiveness of barium naphthenate to increase boiler efficiency can be estimated. A reduction in either or both the mass flow-rate and temperature of the stack gas will increase boiler efficiency. For the barium naphthenate run at 14.2 percent CO_2, an increase of boiler efficiency of about 2 percent is realized. About half of this increase can be attributed to the lower stack-gas temperature while the other half can be attributed to the lower excess air level.

POSSIBLE EFFECTS OF ADDITIVES ON COMBUSTION MECHANISMS

To explain the differences in performance by the various metals which achieved some reduction in the particulate emissions, it is necessary to hypothesize as to the mechanism by which they act. The transition metals--iron, manganese, and cobalt are known to be oxidation catalysts in a variety of chemical systems. Consequently, their activity could be attributed to catalytic enhancement of the carbon burnout in the fly ash. Differences among these metals could result from the degree of catalysis displayed by the particular metal. However, in these experiments no statistically significant difference was found in the performance of these three metals.

The alkaline earth metals--barium and calcium--are not noted for catalytic activity, so the mechanism by which they reduce particulates is very likely different from that of the transition metals. It has been suggested by Friswell(13) that alkaline earth metals may function by promoting the dissociation of water to H atoms and OH radicals, a process occurring only at high temperature. The OH radicals are involved in the combustion of carbon:

$$C + OH \rightarrow CO + H$$

$$CO + OH \rightarrow CO_2 + H.$$

The H atoms in turn react with oxygen in the combustion air to form additional OH radicals and O atoms, namely, $O_2 + OH \rightarrow H + O$.

For differences between various compounds of the same metal, the bond strength between the metal and the remainder of the molecule may be the controlling factor. This aspect was explored most completely for barium. The number of available materials was limited by the necessity that they be soluble in the oil. In this investigation, the naphthenate, hexoate and the sulfonate were used, all of which are barium salts of organic acids. Although some differences in performances of these barium derivatives can be noted in Table 2, more experiments are needed to make a statistically valid evaluation. In the cases of iron and manganese, the situation is similar, although the compounds used cannot be as readily compared. These mechanistic considerations can be used to explain differences, but the possibility should not be eliminated that other properties such as volatility of the additive and the nature of the oil may influence the effectiveness of the additive in reducing particulate emissions.

PERSPECTIVE ON FUEL ADDITIVES

In this study, additives containing certain metals used at concentrations of approximately 20 ppm to 50 ppm of metal in the fuel oil were found effective in reducing particulate emissions. The results of this study, for the most part, have confirmed the observations of other researchers and have extended the range of investigation of proprietary additives and pure compounds to commercial size combustion equipment firing residual fuel oil. It should be pointed out that the mechanisms involved are not fully understood and there is evidence to indicate that additives effective in one system firing one type of fuel may not be effective in another system or when firing a different fuel.

Before any general or widespread use of fuel additive can be recommended, a perspective should be developed for each type of boiler installation to consider:

- Possible toxic effects of pollutant emissions resulting from materials introduced with the additives
- Practical considerations of additives use (such as economics, corrosion resulting from use and increase in other pollutants) other than simply the reduction of one or more pollutants, and
- Comparison of the effectiveness of additives with alternative control means.

It is anticipated that there should be no serious economic penalty with the use of additives as some of the pure compounds are relatively inexpensive. In addition, it should be noted that the level of iron introduced as iron naphthenate was less than the iron present in the oil as ash so that use of iron containing additives for this oil may not introduce any new pollutant. However, the long-term effects of additive use are not well-established nor are the nature and potential toxicity of these metallic compounds adequately defined.

ACKNOWLEDGMENTS

The research upon which this publication is based was performed pursuant to EPA Contract No. 68-02-0262 with the United States Environmental Protection Agency, Division of Control Systems. The authors wish to thank EPA for granting permission to present this material, and to EPA staff members, G. B. Martin and W. S. Lanier who participated in planning this program and have provided helpful comments. The authors also thank other members of the Battelle staff who have contributed to this study--A. E. Weller, A. Levy, P. W. Jones, L. J. Hillenbrand, R. E. Barrett, R. Coleman, T. C. Lyons, and H. G. Leonard--for their advice and assistance in carrying out the research.

REFERENCES

1. Martin, G. B., Pershing, D. W., and Berkau, E. E., "Effects of Fuel Additives on Air Pollutant Emissions From Distillate-Oil-Fired Furnaces", U.S. Environmental Protection Agency, Office of Air Programs, Publication No. AP-87, June, 1971, pp 86.

2. Weeks, R. L., Clinkenbeard, W. L., and Soltis, J. D., "Clean, Efficient Combustion of Heating Oil", Proceedings of the 5th World Petroleum Congress, New York, Section VI, Paper 25, June, 1959, pp 381-396.

3. Riggs, R. J. Wilkinson, C. J., and Wolfe, H. R., "Combustion Improvers for Fuel Oils", Erdoel and Kohle, 18 (4) 282-286 (1965).

4. Perilstein, W. L., "Overbased Barium Sulfonates for Use in Distillate Fuel Oils", U.S. Patent 3,580,707, May 25, 1971, 8 pp.

5. Hangebrauck, R. P., von Lehmden, D. J., and Meeker, J. E., "Sources of Polynuclear Hydrocarbons in the Atmosphere", HEW, A.P. No. 999-AP-33, Durham, N.C., 1967.

6. Committee on Biologic Effects of Atmospheric Pollutants, "Biologic Effects of Atmospheric Pollutants; Particulate Polycyclic Organic Matter", National Academy of Sciences, National Research Council, Washington, D.C., 1972, pp 375.

7. Ray, S. K., and Long, R., "Polycyclic Aromatic Hydrocarbons from Diffusion Flames and Diesel Engine Combustion", Combustion and Flame, 8, 139-151 (1964).

8. Spengler, G. and Haupt, G., "Formation of Soot and Polycyclic Aromatic Hydrocarbons in Simple Hydrocarbon Flames and Its Inhibition by Fuel Additives", Erdoel un Kohle, 22 (11) 679-684 (1969).

9. Pershing, D. W., Martin, G. B., Berkau, E. E., and Hall, R. E., "Effectiveness of Selected Fuel Additives in Controlling Pollution Emissions from Residual Oil-Fired Boilers", U.S. Environmental Protection Agency Report No. EPA-650/2-73, October, 1973.

10. Rendle, L. K. and Wilson, R. D., "The Prevention of Acid Condensation in Oil-Fired Boilers", J. Institute of Fuel, 29, 372 (1956).

11. Jones, P. W., Giammar, R. D., Strup, P. E., and Stanford, T. B., "Efficient Collection of Polycyclic Organic Compounds from Combustion Effluents", presented at the 68th Annual Meeting of the Air Pollution Control Association, Paper No. 75-33.3, Boston, June 15-20, 1975.

12. Standard Method of Test for Smoke Density in the Flue Gases from Distillate Fuels, ASTM Designation: D 2156-65 (Reapproved 1970).

13. Friswell, N. J., Emissions from Continuous Combustion Systems, edited by W. Cornelius and W. G. Agnew, Plenum Press, New York, 1972, p 161.

TABLE 1. ADDITIVES CLASSES

ORGANO-METAL[illegible]

Naphthenates

- Cobalt
- Iron
- Manganese
- Barium
- Iron + barium
- Zinc
- Calcium

Cyclopentadienes

- Manganese - CI-2 (18% Mn)
- Iron - PD 1654 (1% Fe)

Sulfonates

- Barium

Ethyl Hexoate

- Barium

Carbonyls

- Iron

Other

- MC-7 soluble (5% Ba, 2% Mn)
- Rolfite 404 (2% Mn)

ORGANIC

Hydrocarbon

- LSD (C_7H_8, trace metals)
- Improsoot (C_7H_8, trace metals)
- Triple E
- Toluene (C_7H_8, pure hydrocarbons)
- Watcon 130 (trace metals)

Ether

- Diglyme

Alcohol

- Ethyl
- Hexyl

Acid

- Napthenic
- Ethyl hexoic

TABLE 2. SUMMARY OF EVALUATION RUNS

Run	Additive	Dosage	Particulate Loading Additive mg/sm^3	Particulate Loading Baseline mg/sm^3	Particulate Loading Ratio(a)
	a. Initial Evaluation Runs With Proprietary Additives				
1	MC-7 soluble (Apollo)	35 ppm Ba, 14 ppm Mn	31	81	0.61
2	Formula LSD (Commercial Chemical)	3 ppm Co, 4 ppm Mn	77	80	0.93
3	Impresoot (Commercial Chemical)	9 ppm Co, 2 ppm Ca, 10 ppm Mn	48	90	0.58
4	CI-2 (Ethyl Corporation)	21 ppm Mn	100	86	1.20
5	FD 1654 (Arapahoe)	5 ppm Fe	90	77	1.08
	b. Evaluation Runs With Organo-Metallic Additives				
6	Zinc naphthenate	27 ppm Zn	106	115	1.02
7	Cobalt naphthenate	27 ppm Co	74	109	0.71
8	Iron naphthenate	27 ppm Fe	80	127	0.77
9	Iron naphthenate	11 ppm Fe	71	108	0.68
10	Manganese naphthenate	27 ppm Mn	77	106	0.74
11	Calcium naphthenate	27 ppm Ca	62	115	0.60
12	Iron and barium naphthenate	27 ppm Fe, 27 ppm Ba	55	108	0.53
13	Barium naphthenate	51 ppm Ba, 0.05% by volume	48	117	0.46
14	Barium naphthenate	51 ppm Ba	50	92	0.48
15	Barium naphthenate	26 ppm Ba	75	102	0.72
16	Barium naphthenate	10 ppm Ba	89	104	0.86
17	Barium 2-ethyl hexanoate	40 ppm Ba, .03% by volume	55	93	0.53
18	Barium sulfonate	20 ppm Ba	83	98	0.80
19	Iron pentacarbonyl	27 ppm Fe	78	103	0.76
20	CI-2 (Ethyl)	21 ppm Mn	97	105	0.93
	c. Evaluation Runs With Organic Additives				
21	Ethyl hexoic acid	0.03% by volume	102	102	0.98
22	Napthenic acid	0.05% by volume	85	91	0.82
23	Ethyl alcohol	1.5% by volume	101	120	0.97
24	Hexyl alcohol	1.5% by volume	79	86	0.76
25	Diglyme	1.5% by volume	90	104	0.87
26	Toluene	0.2% by volume	114	109	1.05
27	R-4000 (Triple E Products)	0.03% by volume	118	115	1.13
28	R-4000 (Triple E Products)	0.2% by volume	101	110	0.97
29	Formula LSD (Commercial Chemical)	0.2% by volume, 16 ppm Co, 8 ppm Mn	69	100	0.66
30	Watcon 130 (Industrial Chemicals)	0.2% by volume, 16 ppm Fe	66	87	0.63
31	Rolfite 404 (Andrew Rolfe Chemical Co.)	0.2% by volume, 6 ppm Mn	86	102	0.84

d. Evaluation Runs With Variable Boiler Load at Constant Air/Fuel Ratio

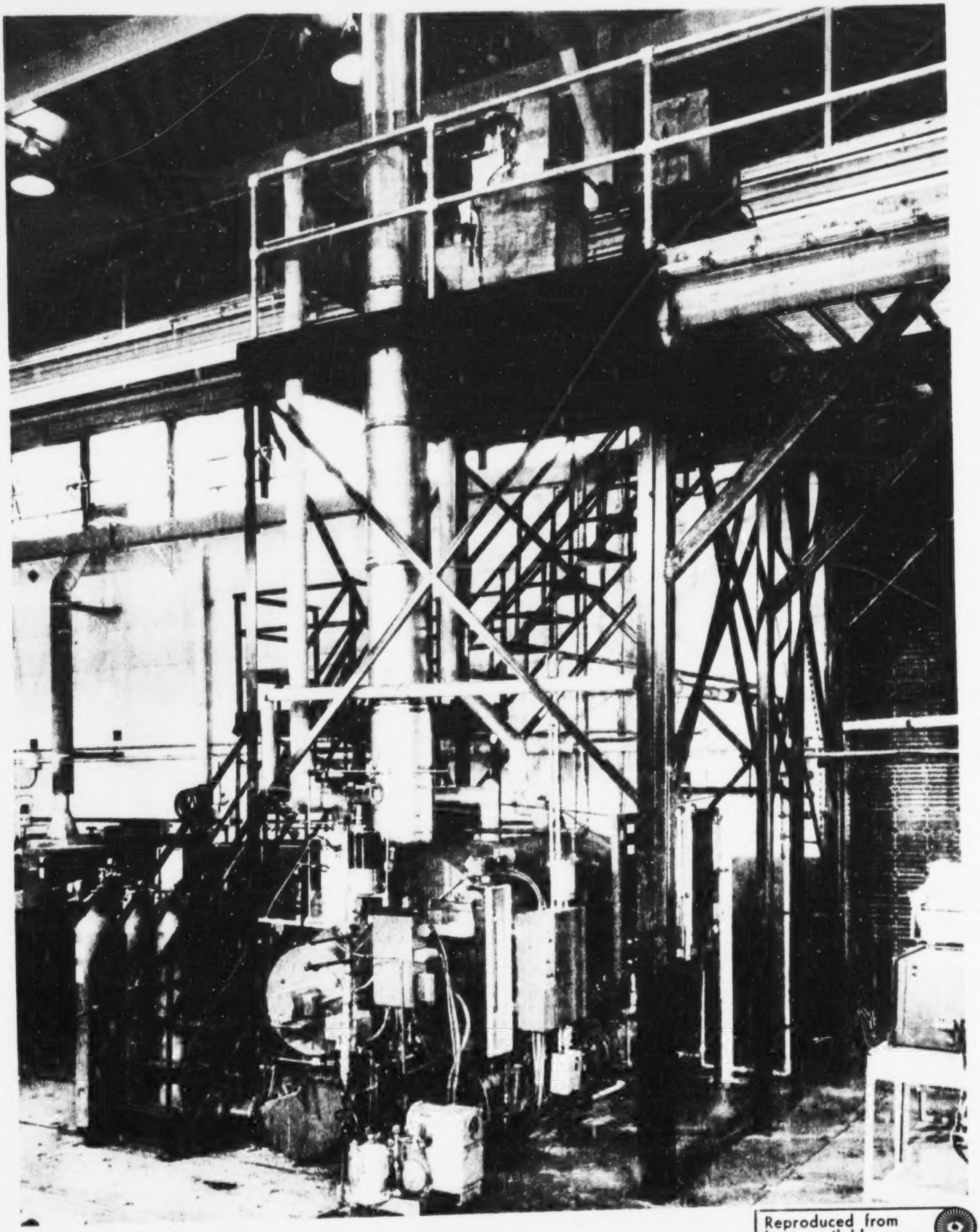
Run	Additive	Dosage	Firing Rate lb/hr	Particulate Loading Additive mg/sm^3 (b)	Particulate Loading Baseline mg/sm^3
32	Barium naphthenate	51 ppm	98	67	148
33	ditto	51 ppm	66	53	115
34	"	51 ppm	54	51	105
35	"	51 ppm	36	55	147

e. Evaluation Run With Cyclic-Boiler Operation

Run	Additive	Dosage	Particulate Loading Additive mg/sm^3	Particulate Loading Baseline mg/sm^3
36	Barium naphthenate	51 ppm	134	206

(a) The ratio of the particulate loading of the additive run and the arithmetic mean of the particulate loadings of the appropriate baseline runs.

(b) lb/hr = 0.454 kg/hr.



Reproduced from
best available copy.

FIGURE 1. EXPERIMENTAL 50-HP BOILER FACILITY

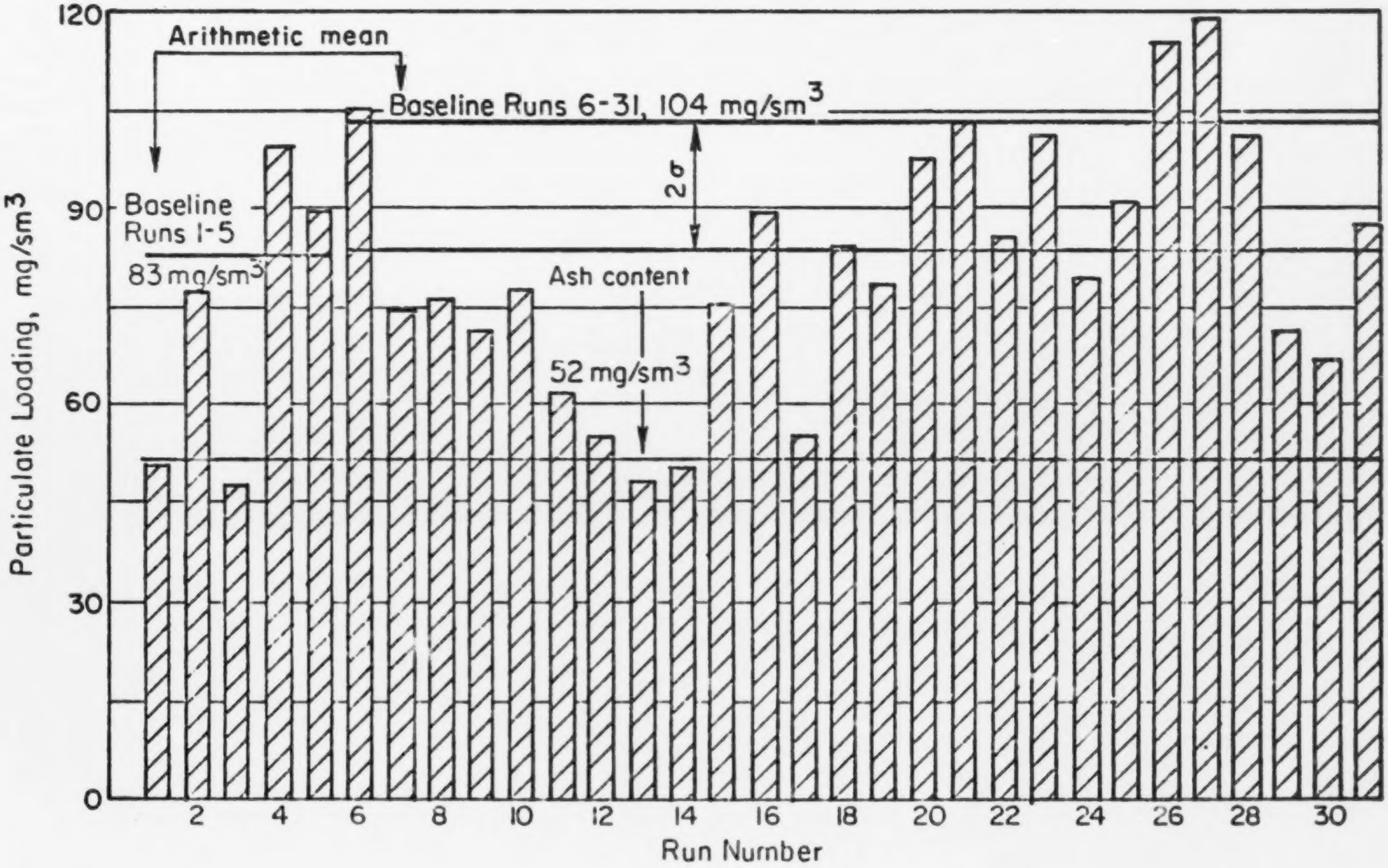


FIGURE 2. SUMMARY OF THE EXPERIMENTAL DATA FOR THE ADDITIVE RUNS AT 80 PERCENT LOAD AND 12.8 PERCENT CO_2

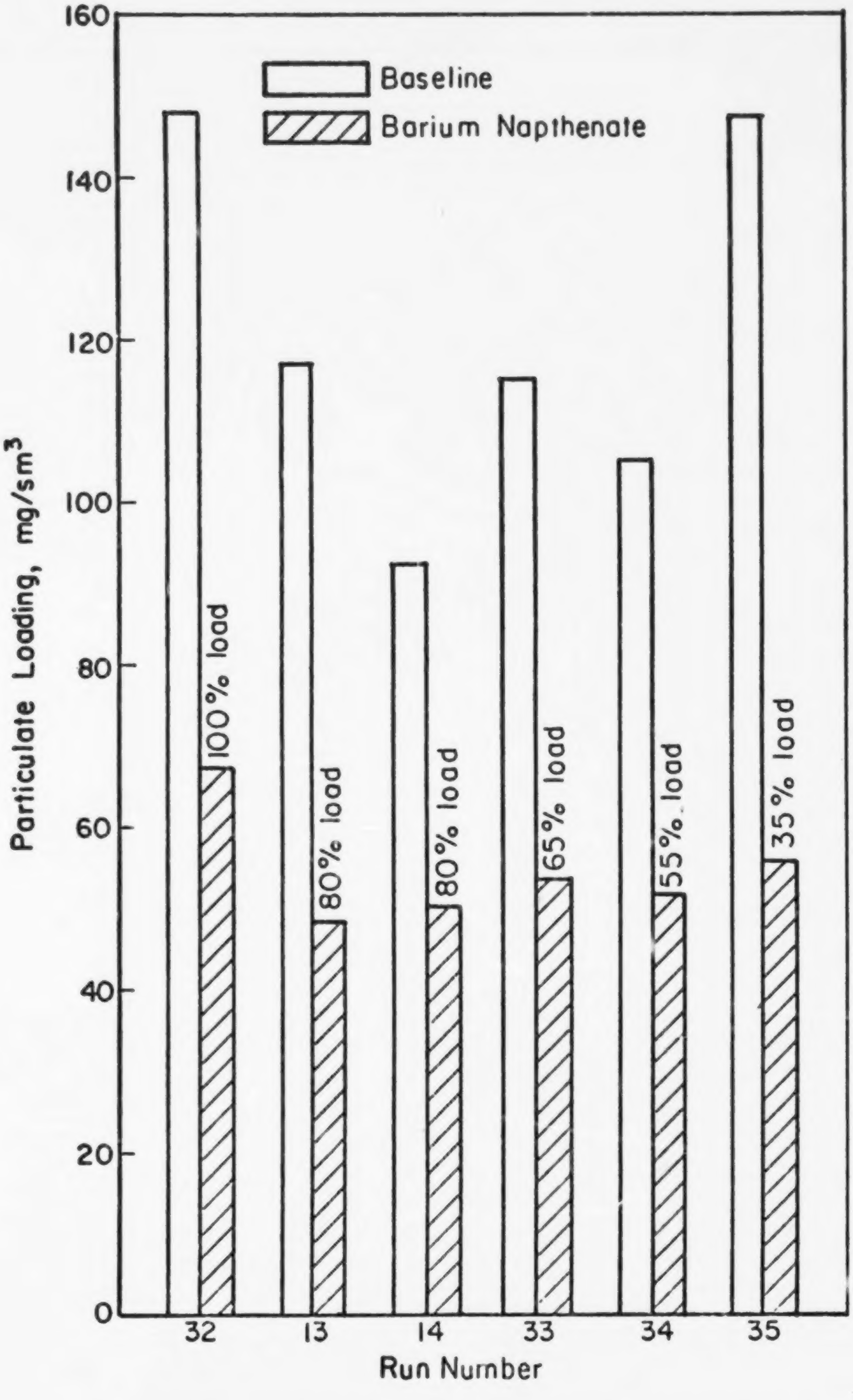


FIGURE 3. THE EFFECTIVENESS OF BARIUM NAPHTHENATE IN REDUCING PARTICULATE AT VARIABLE BOILER LOAD FOR CONSTANT AIR/FUEL RATIO

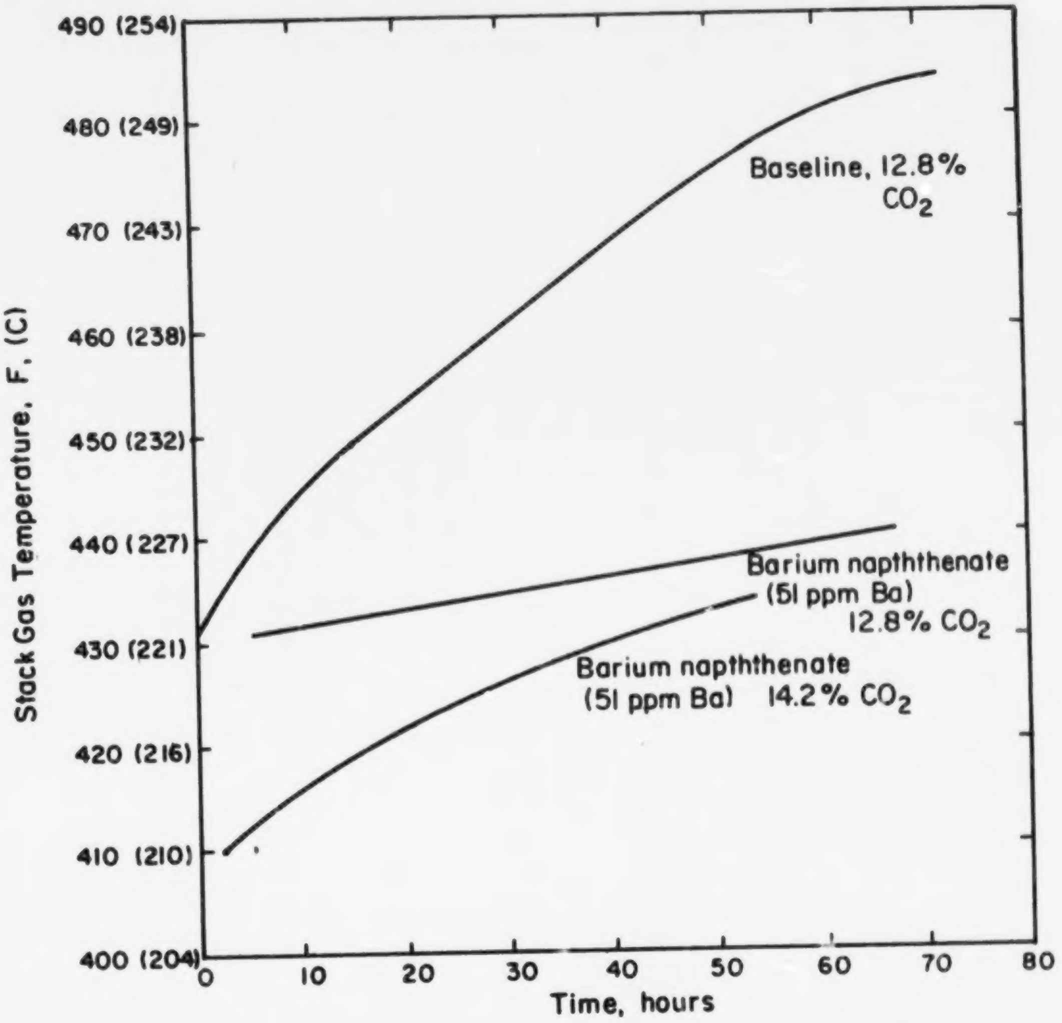


FIGURE 4. STACK-GAS TEMPERATURE AS A FUNCTION OF TIME FIRING 2-PERCENT SULFUR OIL AT 80 LB/HR

5:15 p.m.
The Effect of Additives in
Reducing Particulate Emissions
from Residual Oil Combustion
Robert D. Giammar, Battelle Columbus Labs.

Q: Could you elaborate some more by what you meant by your cyclic operating conditions and why the POM levels were so high?

A: The boiler was operated in a 15 minute on, 5 minute off fashion for 10 cycles. The particulate measurements were made during this period. We suspect that the POM levels were higher during the cyclic mode of operation than the continuous mode of operation because of the characteristic of burner shutdown and startup. During these periods there is poor fuel atomization and some of the oil will get through the vaporized field partially unburned. We found out that our concentrations of POM in raw fuel oil were orders of magnitude higher than the concentrations that we have seen in the stack gases from continuous combustion, and so any unburned fuel collected will give a high POM level.

Q: You had a slide up there which showed stack gas temperature on the vertical axis vs. time for no additives and two different additives. I noticed for one of the additives, at time zero there was significantly lower temperature than the other two. Should all the stack gas temperatures start at the same levels?

A: The air/fuel ratios of these curves were different. In comparison to the two top curves that were for 20% excess air, the lower curve corresponded to 10% excess air. A lower percentage of excess air will give lower stack gas temperature.

Q: That was at a common smoke number.

A: Yes, it is a common smoke number. The lower curve with the additive was a number 4 smoke which was the same as the baseline.

Q: You had mentioned that you did a great deal of testing not only with pure compounds but also with a large number of proprietary additives. If you were asked to make some suggestion, if one of these manufacturers or users were to use a fuel additive, would you care to comment on what your suggestions would be in terms of a particular additive? Should they go to a pure compound? Should they buy a proprietary additive? And what are the economics involved?

A: In our study we found that the alkaline earth metals and the transition metals were effective in reducing particulates or carbon particulates. These were procured in pure compounds...the naphanates, the hexoates...which were significantly less expensive than some of the proprietary additives.

Q: Is any work being planned on the toxicology of the particulates?

A: It's not within the scope of this program.

Q: Would you care to hazard a guess on average residual oil and average set of conditions of operation, the cost of treatment per thousand gallons or a range of possible costs?

A: I don't have those numbers with me. I don't have the specific costs but I made a calculation based upon the following: if you could save a dollar in fuel costs by the use of additives with an increase of efficiency of a couple percent, then you would have to take 20% or 20 cents of that dollar to purchase your additive. I do want to mention, however, that we had to detune this boiler. This boiler could be tuned so that it generated very little carbon particulate and there would have been no point in doing our studies with no carbon particulate. We tried to establish a smoke characteristic curve that was typical of that found in the field, and we relied upon some EPA field study data for this purpose.

Q: Sawyer and co-workers out at Berkeley have shown that several of these additives can significantly affect the particle size distribution by shifting them to lower sizes. Did you try at all to measure the size distribution and, based upon your experimental techniques, would you expect such a shift to alter your conclusions?

A: We did not make any particle size measurements at this time.

Q: Did you run a complete metal analysis on your fuel to find out if you had any substantial trace metals present?

A: Yes. Trace metals were low, less than 150 ppm. The question of how these metallic inerts present in fuel affect the formation of carbon particulate was of concern to us. Some of these trace metals can be present in the oil at higher concentrations than are introduced into the oil with the additive.

Apparently, these trace metals are not nearly as effective as the metallic additives. We suspect, however, that vanadium in some oils might have some effect.

Q: Would you care to rank your alkaline earth metals and your transition metals in terms of their effectiveness as seen by your test?

Q: Statistically, they are equivalent. We just don't have enough data.

Q: Would that be on a molar basis or a weight basis?

A: On a weight basis. It appears that the alkaline earth metals were more effective than the transition metals. Calcium was our best performer, but on a molar basis, calcium and barium gave about the same results.

Q: Several investigators in premixed laboratory flames and diffusion flames have noticed the effect of additive concentration on either promotion or inhibition of soot formation. Did you notice any effect on concentration of your additives?

A: Yes. In our studies we noticed that increasing the metal concentration in the oil almost always decreased the carbon found in the particulate catch. For example, the metallic cyclopentadiennes reduced carbon particulate by only 30% at concentrations of .1 g of metal per gallon of oil but reduced carbon particulate by over 90% at concentrations of 1 g of metal per gallon of oil. However, the resulting total particulate loading would increase.

SYSTEM DESIGN FOR POWER GENERATION FROM LOW BTU GAS

By:

M. P. Heap and T. J. Tyson
Ultrasystems, Inc.
and
N. D. Brown
Combustion Engineering

The work reported in this paper was carried out under EPA Contract 68-02-1361

1.0 INTRODUCTION

The conversion of coal to a clean fuel gas is one attractive method of utilizing the nation's coal reserves in an environmentally acceptable manner. Alternate approaches include the use of fluid bed coal combustors or conventional coal-fired boilers with flue gas desulfurization. This paper addresses the question of how existing technology might best be used to generate electric power from gasifier off-gas. The total study has yet to be completed, therefore this paper represents a partial progress report. The primary objective of the study is to identify those areas which are likely to give rise to emission problems in the design of a 500 MW power plant fired by low Btu coal-derived fuel gas. Having identified problem areas and assessed their magnitude, it is the intent to suggest design modifications to allow these problems to be overcome.

The design study is based upon the provision of a 500 MW power plant with the following characteristics:

- low plant heat rate;
- low NO_x emissions (0.1 lbs $NO_2/10^6$ Btu fired);
- high turndown ratio (5:1);
- low capital cost;
- low operating cost.

The restrictions placed on the study prevented any consideration of integrated power plant/gasifier systems and it was required that the economic analysis be conducted on the basis of purchased coal gas, necessitating an assessment of an "over the fence" cost.

2.0 SYSTEMS STUDY

2.1 Fuel Characteristics

The systems study was carried out on the basis that two general classes of fuel gas can be considered as representative of existing technology:

- a low Btu gas typical of that produced by a Lurgi air blown gasifier;
- a medium Btu gas typical of that produced by an oxygen blown Koppers Totzek (K-T) system.

The compositions of these two fuels are presented in Table 1.

Table 1. Fuel Gas Compositions for the Systems Study (After 1)

	Low Btu (Lurgi)	Medium Btu (K-T)
CO	14.1 %	53
H_2	20.9 %	36.4
CH_4	5.8 %	-
CO_2	12.5 %	9.25
H_2O	6.6 %	0.3
N_2	40.1 %	1.05
LHV (Btu/scf @ 60°F 1 atmos)	160	272

In addition to variations in heating value it was also considered that the fuel gas may be available at high pressure (in excess of 10 atmospheres) and high temperature (approximately 1500°F). It has been shown that coal gas combined cycle power plant systems only have an overwhelming economic advantage over conventional plants if advanced turbine concepts allowing turbine inlet temperatures of 2600°F can be used(2). High temperature/pressure fuel gas was included in this study for purposes of comparison, although the assessment of fuel cost presented a problem.

2.2 Systems Considered

Over forty conceptual power plant systems were considered which were capable of using the fuel gases discussed above. These concepts can be classified into four groups:

1. Conventional boiler systems with low temperature fuel gas or systems which include either a fuel gas precooler or high temperature burners to utilize high temperature fuel gas.
2. Combined cycle systems of the waste heat and auxiliary fired steam boiler type.
3. Supercharged boiler systems.
4. Oxygen-fired boilers - if oxygen is available in bulk for the gasification process then it could also be utilized in the power plant.

Each of these four general classes includes a wide spectrum of system concepts. After all the concepts had been studied, five were chosen for more detailed consideration. These systems are listed in Table 2. System A1 was chosen because it represents a baseline case suitable for retrofit. Waste heat combined cycle plants were not considered because they were being studied in detail in another EPA-sponsored project(2).

Table 2. Power Plant Systems Studied in Detail

SYSTEM	A1	B1	C1	H1	A1	I5
FUEL	LURGI LBG	LURGI LBG	LURGI LBG	LURGI LBG	K-T MBG	K-T MBG
FUEL TEMP (°F)	250	1500	1500	654	250	250
FUEL PRESS. (PSIG)	10	10	10	162	10	10
SYSTEM DESCRIPTION	CONVENTIONAL STEAM PLANT	CONVENTIONAL STEAM PLANT WITH GAS PRECOOLER	CONVENTIONAL STEAM PLANT WITH HI TEMP. BURNERS	SUPER-CHARGED BOILER COMB. CYCLE	CONVENTIONAL STEAM PLANT	O_2 BLOWN STEAM PLANT
COMMENT		FUEL ENTERS PLANT @ 1500°F IS COOLED TO 750°F IN WASTE HEAT BOILER AND FIRED THROUGH CONVENTIONAL BURNERS.	FUEL ENTERS PLANT @ 1500°F AND IS FIRED THROUGH HI TEMP. BURNERS.	TURBINE INLET TEMP. 2000°F, FURNACE PRESS. 10 ATM. GAS TURBINES 38% OF OUTPUT		OXYGEN USED IN FURNACE INSTEAD OF AIR. FGR PROVIDED TO REDUCE PEAK TEMPERATURES

Detailed heat and mass balances were conducted for each of the five systems which were then compared on the basis of their capital and operating costs. The intent in each case being to design a system which would satisfy the goals described earlier.

With the exception of System H1, each of the plant designs consisted of a single balanced draft Controlled Circulation boiler with a single cell furnace. Tangential and alternate opposed - wall burner designs were considered for these plants which have a maximum continuous rating of 3,310,000 lbs/hr main steam flow with superheat and reheat steam conditions of 1011^{o}F/2685 psig and 1001^{o}F/501 psig respectively. Superheat steam temperature control is achieved by the addition of a water spray to an interstage desuperheater; reheat steam temperature control is accomplished via burner tilt or gas recirculation. Extremely high gas recirculation (205 percent) has been included in the O_2 fired steam plant (System I5) in order to keep peak gas (and hence metal) temperatures within acceptable limits. A net plant output of 500 MW would be delivered by a single steam turbine generator set.

Figure 1 presents a conceptual sketch of one of the 10 atmosphere once through boiler included in the supercharged boiler combined cycle plant (System H1). A simplified flow scheme of the same plant is shown in Figure 2 which contains three boilers. The boiler design allows Lurgi gas to be fired through a single fixed van burner located at the bottom of the furnace (see Figure 1). Each of the supercharged boilers

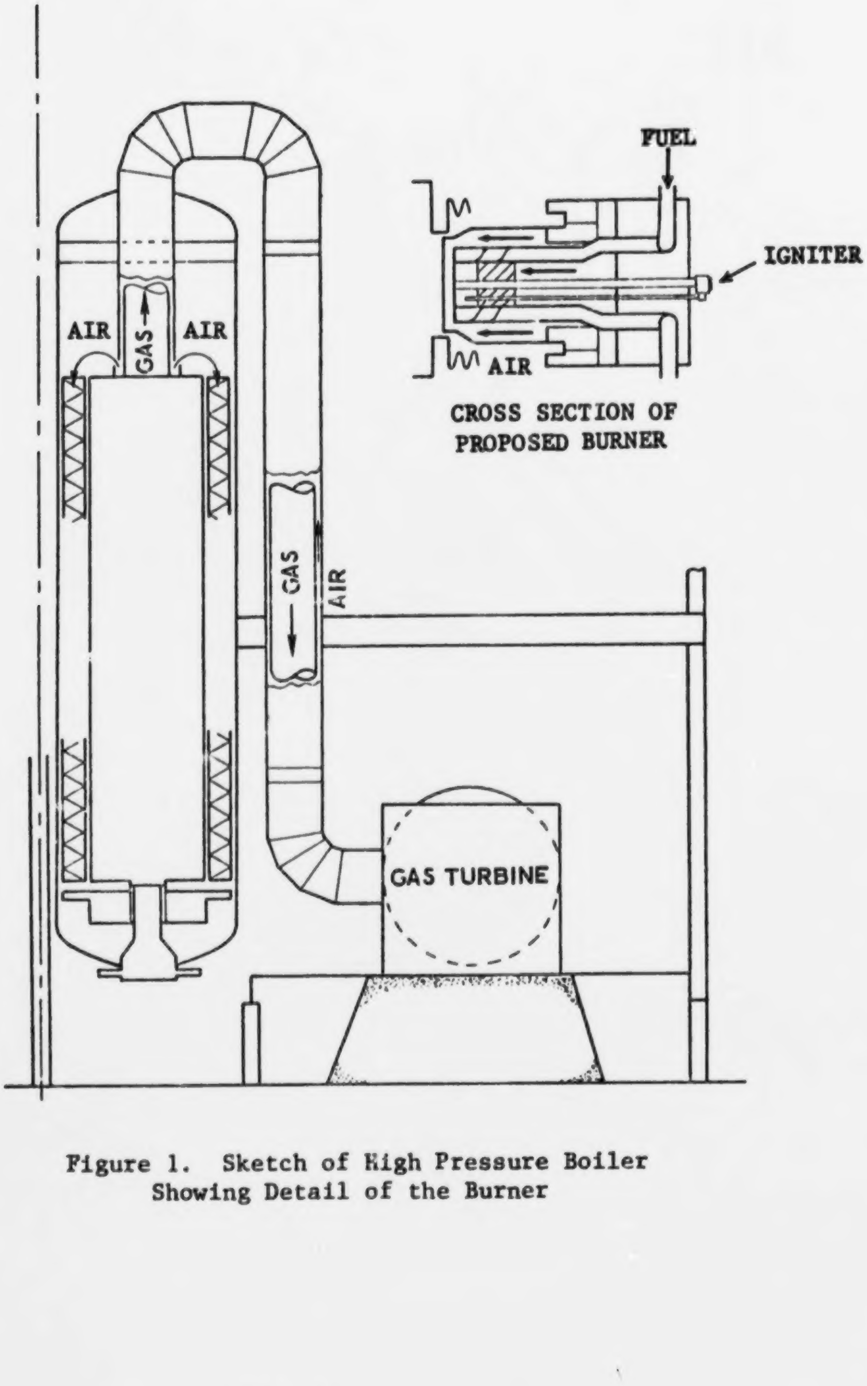

FUEL
IGNITER
AIR
CROSS SECTION OF PROPOSED BURNER
AIR
GAS
AIR
GAS
AIR
GAS TURBINE

Figure 1. Sketch of High Pressure Boiler Showing Detail of the Burner

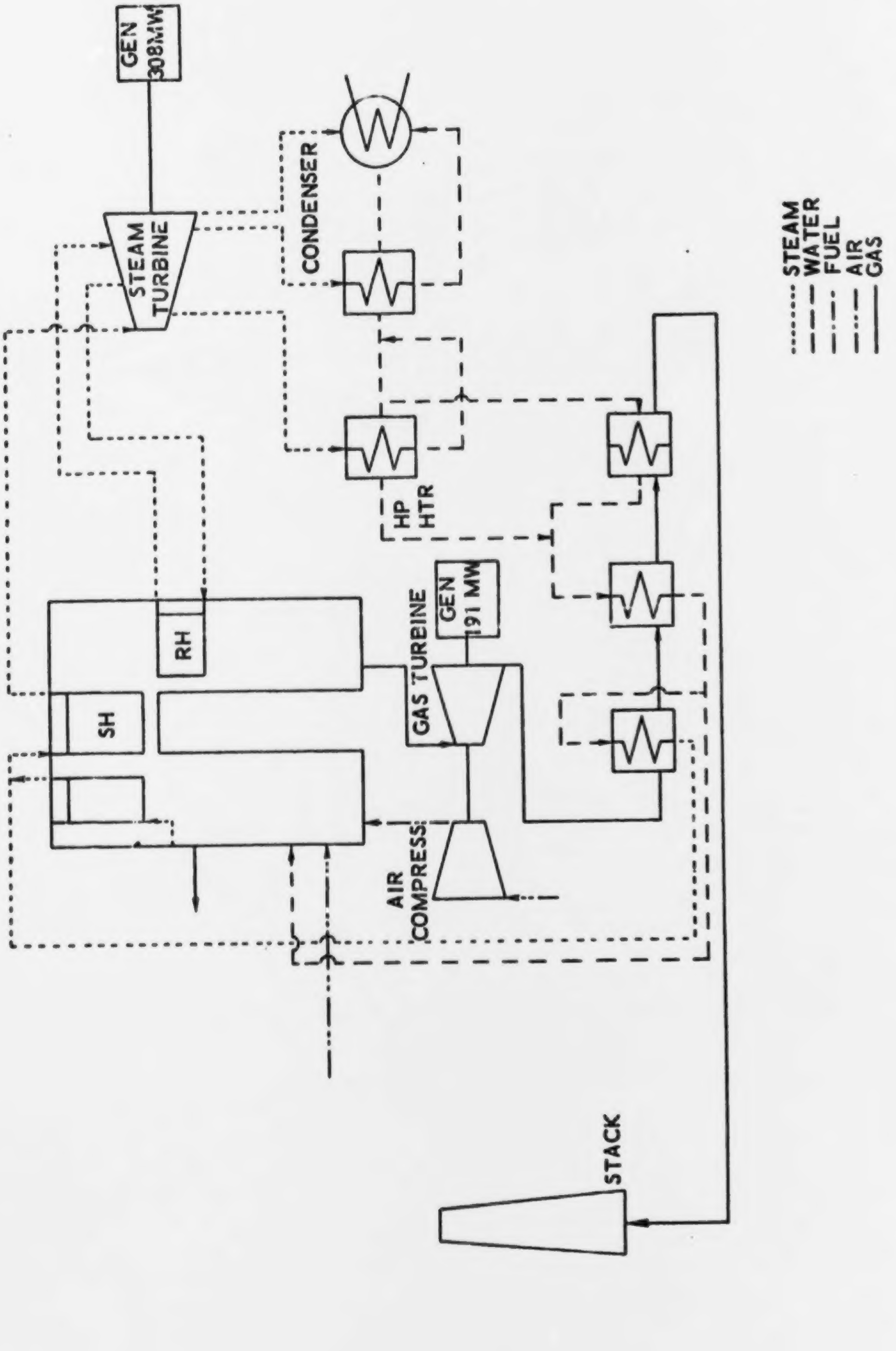

GEN 308MW
STEAM TURBINE
CONDENSER
HP HTR
RH
SH
GEN 191 MW
GAS TURBINE
AIR COMPRESS
STACK
STEAM
WATER
FUEL
AIR
GAS

Figure 2. Simplified Flow Scheme for System H1

has a maximum continuous rating of 612,000 lbs/hr main steam flow with superheat and reheat steam conditions of 1011°F/2685 psig and 1001°F/501 psig respectively. Superheat and reheat steam temperature control is achieved via desuperheat spray. Flue gas leaves the boilers at 2000°F and is delivered to three gas turbines; heat losses from the system are minimized by routing the air from the compressors to the boilers in an annulus surrounding the flue gas pipe. Upon leaving the gas turbines, the flue gas passes through a waste heat recovery chain consisting of an evaporator-superheaters, economizer and a feedwater heater. The flue gas at 300°F then passes to the stack. The three gas turbine generator sets deliver a total net output of 191 MW; a single steam turbine generator delivers 308 MW net.

Calculated plant performance for each of the five systems is summarized in Table 3.

2.3 System Economics

Capital cost estimates have been prepared for each system assuming all plants were outdoor-type located at an average U.S. site using the standard Federal Power Commission account numbering system. The performance and operating costs for 1974 operation are summarized in Table 4, and the terms used in this table are defined in Table 5. The gross electrical output of each plant is approximately 520 MW and has been corrected for typical auxiliary power requirements for

Table 3. Summary of Plant Performance

SYSTEM FUEL DESCRIPTION FIGURE	A1 LURGI LBG CONVENTIONAL STM. PLANT 1A	B1 LURGI LBG STEAM PLANT WITH FUEL PRECODER 1B	C1 LURGI LBG STEAM PLANT WITH HI TEMP. BURNERS 1C	H1 LURGI LBG SUPERCH. BOILER COMB. CYC. PLANT NO.	A1 K-T MBG CONVENTIONAL STM. PLANT 1E	I5 K-T MBG O_2 BLOWN STM. PLANT 1F
NET POWER PLANT EFF. %	36.2	36.3	36.3	43.7	37.8	38.2
NET POWER PLANT HEAT RATE BTU 1 KW HR	9440	9420	9420	7814	9040	8920
HHV HEAT ENERGY INPUT 10^6 BTU/HR	4720	4710	4710	3899	4520	4460
NET POWER PLANT OUTPUT MW	500	500	500	499	500	500
STEAM TURBINE OUTPUT MW	500	500	500	308	500	500
STEAM TURBINE THROTTLE CONDITIONS PSIA/°F/°F	2535/1000/1000	2535/1000/1000	2535/1000/1000	2535/1000/1000	2535/1000/1000	2535/1000/1000
STEAM TURBINE BACK PRESS. INCH H_g	3.5	3.5	3.5	3.5	3.5	3.5
GAS TURBINE PWR. OUTPUT MW	---	---	---	191	---	---
GAS TURBINE INL. TEMP. °F	---	---	---	2000	---	---
GAS TURBINE BACK PRESS. PSIA	---	---	---	15.2	---	---
PWR. PLANT AUX. PWR. MW	17.4	16.4	16.4	5.2	15.4	16.4
STACK TEMP. °F	250	300	300	300	250	350
STM. TURBINE OUTPUT %	100	100	100	61.7	100	100

Table 4. Summary of Operating Costs for 1974 Operation

PLANT NUMBER		A1	B1	C1	H1	A1	I5
		CONVENT LURG LBG	CONVENT LURG LBG	CONVENT LURG LBG	COMBINED PRESSRZD	CONVENT K-T MBG	OXY AL WN K-T MBG
NOMINAL PLANT OUTPUT	MW	500.	500.	500.	499.	500.	500.
NET PLANT HEAT RATE		9440.	9420.	9420.	7814.	9040.	8920.
NUMBER OF GAS TURBINES		0.	0.	0.	3.	0.	0.
STEAM THROTTLE PSIG		2520.	2520.	2520.	2520.	2520.	2520.
SH DEGF		1000.	1000.	1000.	1000.	1000.	1000.
REHEAT DEGF		1000.	1000.	1000.	1000.	1000.	1000.
WASTE HEAT FW HEATER		0.	1.	0.	3.	0.	0.
GROSS PLANT OUTPUT	MW	520.0	519.0	519.0	506.8	518.0	519.0
AUXILIARY POWER	MW	17.4	16.4	16.4	5.2	15.4	16.4
TRANSFORMER LOSSES	MW	2.6	2.6	2.6	2.6	2.6	2.6
NET OUTPUT	MW	500.0	500.0	500.0	499.0	500.0	500.0
ANNUAL NET GENERATION MILLION KWHR							
AT 5000 HR/YR		2500.	2500.	2500.	2495.	2500.	2500.
AT 7500 HR/YR		3750.	3750.	3750.	3742.	3750.	3750.
CAPITAL COSTS -- $1000		125947.	125771.	122101.	116786.	121344.	121491.
FUEL COST -- $/MIL BTU		1.25	1.25	1.25	1.40	1.50	2.05
ANNUAL FIXED CHARGES AT 20.0 % / YR $1000		25189.	25154.	24420.	23357.	24269.	24298.
ANNUAL OPERATING AND MAINT. LABOR $1000		1320.	1320.	1320.	1320.	1320.	1320.
ANNUAL MAINTENANCE MAT. & SUPPLIES $1000							
AT 5000 HR/YR		1040.	1038.	1038.	1394.	1036.	1038.
AT 7500 HR/YR		1560.	1557.	1557.	2091.	1554.	1557.
ANNUAL FUEL COST $1000							
AT 5000 HR/YR		29550.	29437.	29437.	27294.	33900.	45715.
AT 7500 HR/YR		44250.	44156.	44156.	40941.	50850.	68572.
TOTAL ANNUAL OPERATING COSTS $1000							
AT 5000 HR/YR		57049.	56950.	56216.	53365.	60525.	72371.
AT 7500 HR/YR		72319.	72187.	71453.	67709.	77993.	95748.
ENERGY COST MILLS/KWHR							
AT 5000 HR/YR		22.820	22.780	22.486	21.389	24.210	28.948
AT 7500 HR/YR		19.285	19.250	19.054	18.092	20.798	25.533

Table 5. Definition of Terms Used in Cost Summary

1. $\text{NET PLANT HEAT RATE} = \dfrac{\text{TOTAL FUEL FIRED}}{\text{GROSS MW - AUXILIARY POWER}} = \dfrac{\text{TOTAL FUEL FIRED}}{\text{NET PLANT MW}}$

2. ANNUAL NET GENERATION = NET PLANT MW X HOURS

3. MAINTENANCE MATERIAL AND SUPPLY COST = GROSS KWHRS/YR X MILLS/KWHR COST

4. $\text{ANNUAL FUEL COST} = \begin{matrix}\text{ANNUAL NET}\\ \text{GENERATION}\end{matrix} \times \begin{matrix}\text{NET PLANT}\\ \text{HEAT RATE}\end{matrix} \times \begin{matrix}\text{FUEL}\\ \text{COST}\end{matrix} \ (\$/10^6\ \text{BTU})$

5. $\begin{matrix}\text{TOTAL ANNUAL}\\ \text{OPERATING COST}\end{matrix} = \begin{matrix}\text{ANNUAL}\\ \text{CAPITAL}\\ \text{COST}\end{matrix} + \begin{matrix}\text{ANNUAL}\\ \text{FUEL}\\ \text{COST}\end{matrix} + \begin{matrix}\text{ANNUAL}\\ \text{LABOR}\\ \text{COST}\end{matrix} + \begin{matrix}\text{ANNUAL}\\ \text{MAINTENANCE}\\ \text{MATERIALS}\end{matrix}$

6. $\text{UNIT ENERGY COST} = \dfrac{\text{TOTAL ANNUAL OPERATING COSTS}}{\text{ANNUAL NET GENERATION}}$

condenser cooling pumps, boiler circulating pumps, FD, ID and GR fans. Transformer losses are 0.5 percent of the net output. The boiler feed pumps are steam turbine driven and are included in the steam cycle. The net plant heat rate is the gross (higher heating value plus sensible) fuel heat input divided by the net output.

Annual net generations are the net full load output times 5000 and 7500 hours per year. These are equivalent to load factors of 57 and 86 percent. A fixed charge rate of 20 percent of capital cost per year is assumed as typical for an average U.S. site. Annual fuel costs for 1974 are based on $\$1.25/10^6$ Btu as the delivered price for 10 psig Lurgi LBG and $\$1.40/10^6$ Btu for 147 psig Lurgi LBG. The delivered price for Koppers Totzek MBG is $\$1.50/10^6$ Btu; plant I5 has an additional cost of $\$0.55/10^6$ Btu for oxygen for the boiler, resulting in a total of $\$2.05/10^6$ Btu. In order to arrive at a realistic cost of the high pressure Lurgi gas, an evaluation of the relative gasifier capital costs for low versus high pressure fuel gas yielded an increased cost of $\$0.15/10^6$ Btu for the high pressure gas. This is associated with the increased auxiliary power requirements for the gasifier because the product gas expanded to 10 psig.

2.4 Discussion

Table 6 summarizes the plant costs and performance of the five power plant systems considered suitable for the application of existing

Table 6. Summary of Plant Performance and Operating Costs

PLANT NUMBER	A1 CONVENT LURG LBG	B1 CONVENT LURG LBG	C1 CONVENT LURG LBG	H1 COMBINED PRESSRZD	A1 CONVENT K-T MBG	I1 OXY ALWN K-T MBG
NET POWER PLANT OUTPUT MW	500	500	500	499	500	500
NET POWER PLANT HEAT RATE BTU/KR HR	9440	9420	9420	7814	9040	8920
NET POWER PLANT EFFICIENCY	36.2	36.3	36.3	43.7	37.8	38.3
STACK TEMPERATURE ^{o}F	250	300	300	300	250	350
TOTAL ESTIMATED COST \$ X 10^{-3}	125947	125771	122101	116786	121344	121491
\$ NET KW	252	252	244	234	243	243
ENERGY COST 7500 HR/YR MILLS/KW	19.285	19.250	19.054	18.092	20.798	25.533
ESTIMATED EMISSIONS LBS $NO_2/10^6$ BTU	.0013	.0030	.025	.013 to .34	.15	.000075

technology to the utilization of gasifier off-gas for power generation. The supercharged boiler combined cycle plant (H1) has the lowest capital costs per KW and the lowest net heat rate which results in the lowest fuel costs. The three other Lurgi LBG plants (A1, B1 and C1) have nearly identical unit energy costs approximately 6 percent higher than Plant H1. Plant A1 for the Koppers Totzek fuel has unit energy costs approximately 16 percent higher than Plant H1; the cost for this plant exceeds that of the other Lurgi plants due to the higher fuel cost. Koppers Totzek plant I5 energy cost is approximately 36 percent higher than Plant H1; the high energy cost of this plant is a result of the use of oxygen in the boilers.

Although the supercharged boiler combined cycle system has both the lowest capital and energy costs, the advantage is hardly overwhelming. Supercharged boilers have been used throughout Europe, but their use in the States has been restricted to marine boilers. Robson(3) had earlier considered the use of supercharged boilers and rejected them for the following reasons:

- the development costs associated with their construction was likely to be too high;
- as permissible turbine inlet temperatures increase, the efficiency advantage of the supercharged boiler system disappears.

In a study conducted for the Office of Coal Research(4) Combustion Engineering compared the cost of conventional steam plants with an atmospheric gasifier and supercharged boiler combined cycle plant with pressurized gasifiers. In this study which considered an integrated gasification and power generation plant, the supercharged boiler concept had a 3.0 Mills/KW energy cost advantage.

Even if a supercharged boiler can be considered as existing technology, there does not appear to be a clear-out financial incentive to recommend its use. This is compounded by the environmental considerations presented in the following section clearly indicating that further detailed study is required before the supercharged boiler combined cycle system can be considered to be an acceptable method of power generation from coal gasifier off-gas.

3.0 ENVIRONMENTAL CONSIDERATIONS IN THE COMBUSTION OF GASIFIER OFF-GAS

The systems study discussed in the previous section was based upon the delivery of a fuel gas almost free from sulfur (i.e., less than that which would exceed SO_2 emission standards) and particulates. Since the gasification process is not included in the study, the major area giving rise to environmental concern is the formation of NO_x during the combustion of the low Btu gas. The kinetic mechanisms controlling the rate of NO_x formation in combustion processes are outside the scope of this paper. However, it is known that the amount of NO_x formed from molecular nitrogen is strongly temperature dependent. Thus, thermal NO formation is unlikely to be a problem in any of the systems discussed earlier (perhaps with the exception of system H1) provided the fuel gas is burned with air or oxygen and sufficient quantities of recycled cooled combustion products. The emission levels shown in Table 6 were calculated by the NO_x Emission Subroutine of the Lower Furnace Program(5). For tangentially fired units there is sufficient experience to believe that these emission levels will be within acceptable predictive limits. The Lurgi fired systems are so below the target emission level that NO control techniques need not be considered. This does not apply to the K-T fired boiler (A1), the higher heating value and higher flame temperatures necessitate some type of control to meet the 0.1 lbs $NO_x/10^6$ Btu target.

Predictions for the supercharged boiler must be considered as less acceptable. It should be recognized that these predictions were made with a model tuned to a particular furnace design. The prediction can be considered to be suspect because

- the upfired boiler may give a very different heat flux distribution from that expected based upon tangential firing experience;
- it may no longer be permissible to treat the furnace as a series of horizontal strips of uniform properties;
- the lower furnace model does not include the capability of accepting pressures above atmospheric.

One other real concern is the possibility of trace quantities of ammonia in the fuel gas. It is known that ammonia is one of the products of most gasification schemes and that it will be oxidized to NO during the combustion process. The emission levels indicated above did not include the possible conversion of ammonia contained in the fuel gases. The best available estimates(2) indicate that after low temperature H_2S clean-up the fuel gas may contain 500 ppm of ammonia. This could produce as much as 200 ppm of NO_x in the combustion products, depending upon the fuel-air mixing process within the combustor. Existing processes for high temperature H_2S removal do not scrub ammonia and the high temperature gas may contain as much as 4000 ppm of ammonia which would give NO_x levels in excess of the N.S.P.S. (New Source Performance Standards) unless appropriate precautions were taken.

4.0 CONCLUSIONS

A systems study has been conducted to assess the most appropriate use of existing technology to produce electric power from low Btu gas in an environmentally acceptable manner. Fired gas turbines could ultimately lead to the most economically advantageous use of this fuel provided turbines can be built to operate satisfactorily for prolonged periods with inlet temperatures of 2600°F. The present study indicates that a supercharged boiler unfired gas turbine system provides the best method of utilizing existing technology to convert coal-derived fuel gas to electric power. The analysis discussed earlier gives slight economic advantage for the supercharged boiler. However, it should be noted that there may be considerable economics associated with the design and construction of an integrated plant. The net power plant heat rate for this system is significantly lower than those of the other systems studied, suggesting that a more detailed study of an integrated plant might uncover a more significant advantage. There should be little need for concern regarding NO_x production from low Btu gas provided it is used cold and free from significant quantities of ammonia. The study has highlighted the need for an analytical tool capable of predicting combustor performance. Work is in progress to assess the NO_x emissions from a supercharged boiler fired by coal-derived fuel gas which could contain up to 500 ppm of ammonia, and to identify those design parameters which will allow emissions to be controlled to a minimum without impairing the thermal efficiency of the system.

REFERENCES

1. Martin, G.B., "Environmental Considerations in the Use of Alternate Fuels in Stationary Combustion Processes." (Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology, EPA-650/2-74-118, pp 259-275; NTIS No. PB 238-304/AS. (October, 1974).)

2. Robson, F.L., Blecher, W.A. and Giramonti, A.J., "Combined Cycle Power Systems", (Presented at the Symposium on Environmental Aspects of Fuel Conversion Technology II, Hollywood, Florida, December, 1975.

3. Robson, F.L., and Giramonti, A.J., "The Environmental Impact of Coal-Based Advanced Power Systems." (Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology, EPA-650/2-74-118, pp 237-257; NTIS No. PB 238-304/AS. (October, 1974).)

4. Review and Evaluation of New Plant Gasifier/Power System Alternatives, Task 4, Office of Coal Research, Project No. 900129, Combustion Engineering.

5. Beuters, K.A., Cogoli, J.G. and Habelt, W.W., Fifteenth Sumposium (International) on Combustion, p 1245, The Combustion Institute (1075).

SPEAKERS LIST

(NOTE: To facilitate their identification, speakers are listed alphabetically together with the name of the organization they represent. The complete address of each organization represented at the conference appears at the end of the list of attendees.)

LIST OF SPEAKERS

Name	Representing
Axworthy, Dr. Arthur E.	Rockwell International, Rocketdyne Division
Bittner, James D.	Massachusetts Institute of Technology
Bowen, Dr. Joshua A.	EPA, IERL, Combustion Research Branch
Bowman, Dr. Craig T.	United Technology Research Center
Brown, Richard A.	Acurex, Aerotherm Division
Burchard, Dr. John K.	EPA, IERL
Cato, Glenn A.	KVB, Inc.
Collom, Jr., Robert H.	State of Georgia, Department of Natural Resources
Combs, L. Paul	Rockwell International, Rocketdyne Division
Crawford, Allen R.	Exxon Research and Engineering
Cuffe, Stanley T.	EPA, Office of Air Quality Planning and Standards
Dykema, Owen W.	The Aerospace Corporation
England, Dr. Christopher	Jet Propulsion Laboratory
Engleman, Dr. Victor S.	Exxon Research and Engineering
Giammar, Robert P.	Battelle-Columbus Laboratories
Hall, Robert E.	EPA, IERL, Combustion Research Branch
Heap, Dr. Michael P.	Ultrasystems
Helms, G. Thomas	EPA, Region IV, Air and Hazardous Materials Division
Hollinden, Dr. Gerald A.	Tennessee Valley Authority
Kason, T.T.	City of Chicago, Department of Environmental Control
Kendall, Dr. Robert M	Acurex, Aerotherm Division
Kesselring, Dr. John P.	Acurex, Aerotherm Division
Ketels, Peter	Institute of Gas Technology
Lachapelle, David G.	EPA, IERL, Combustion Research Branch
Lanier, W. Steven	EPA, IERL, Combustion Research Branch
McDonald, Henry	United Technology Research Center
Maloney, Dr. Kenneth L.	KVB, Inc.
Manny, Erwin H.	Exxon Research and Engineering
Martin, G. Blair	EPA, IERL, Combustion Research Branch
Muzio, Dr. Lawrence J.	KVB, Inc.
Pohl, John H.	Massachusetts Institute of Technology
Poston, H. Wallace	City of Chicago, Department of Environmental Control
Princiotta, Frank	EPA, Energy Processes Division
Rosenberg, Dr. Robert B.	Institute of Gas Technology
Sarofim, Dr. Adel F.	Massachusetts Institute of Technology
Selker, Ambrose P.	Combustion Engineering
Shaw, Dr. Robert	Stanford Research Institute
Shoffstall, Dr. Donald R.	Institute of Gas Technology
Tyson, Dr. Thomas J.	Ultrasystems
Wasser, John H.	EPA, IERL, Combustion Research Branch
Wendt, Dr. Jost O.L.	University of Arizona

PARTICIPANTS LIST

(NOTE: To facilitate their identification, participants are listed alphabetically together with the name of the organization they represent. The complete address of each organization represented at the conference appears at the end of the list of attendees.)

LIST OF PARTICIPANTS

Name	Representing
Alvey, Courtney D.	Baltimore Gas & Electric
Anderson, Dr. Larry W.	Acurex, Aerotherm Division
Axtman, William H.	American Boiler Manufacturers Association
Bagwell, Fred A.	South California Edison
Baker, Burke	Shell Development Company
Ban, Stephen D.	Battelle-Columbus Laboratories
Barrett, Richard E.	Battelle-Columbus Laboratories
Barsin, Joseph	Babcock & Wilcox
Bartok, William	Exxon Research & Engineering
Batra, Sushil K.	New England Electric Systems
Bauman, Robert D.	EPA, Office of Air Quality, Planning & Standards
Beals, Rixford A.	NOFI
Beatty, James D.	Procter & Gamble
Bennett, Dr. Robert	Apollo Chemical
Blandford, Jr., J.B.	Englehard Industries
Blythe, R. Allen	International Boiler Works
Buechler, Lester	Systems Research Labs
Bonne, Ulrich	Honeywell
Booth, Michael R.	Ontario Hydro
Bowman, Barry R.	Lawrence Livermore Laboratories
Bueters, K.A.	Combustion Engineering
Carpenter, Ronald C.	Armstrong Cork
Cernansky, Dr. Nicholas P.	Drexel University
Christiano, John P.	EPA, Office of Air Quality, Planning & Standards
Chu, Richard R.	EBASCO
Clark, Norman D.	C-E Air Preheater
Cleverdon, R.F.	Chevron Research Company
Cotton, Ernest	American Petroleum Institute
Creekmore, Andrew T.	EPA, Control Programs Development Division
Daughtridge, Jimmy T.	Pratt & Whitney Aircraft
Degler, Gerald H.	Systems Research Labs
Demetri, E.P.	Northern Research and Engineering Corporation
DeWerth, D.W.	American Gas Association Labs
Dingo, T.T.	General Motors
Donaldson, Thomas M.	EPA, Office of Air Quality, Planning & Standards
Dowling, Daniel J.	Union Carbide
Downey, Thomas A.	Gamlen Chemical Company
Dyer, T. Michael	Sandia Laboratories
Dygert, J.C.	Shell Development Company

LIST OF PARTICIPANTS (CONT'D)

Name	Representing
Dzuna, Eugene R.	Gulf Research & Development Company
Erskine, George	Mitre Corporation
Feng, C.L.	Selas Corporation of America
Fennelly, Paul F.	GCA/Technology Division
Fletcher, James	Industrial Combustion
Fletcher, Roy J.	Peabody Engineering Corporation
Freelain, Kenneth	Federal Energy Administration
Frisch, Dr. N.W.	Research-Cottrell
Fuhrman, Jr., Theodore C.	Erie City Energy Division
Gibbs, Thomas	EPA, Region IV
Goetz, Gary	Combustion Engineering
Goodley, Allan R.	California Air Resources Board
Graham, David J.	EPA, Office of Research and Development
Greene, Jack H.	EPA, Administrative Office
Grimshaw, Vincent C.	Process Combustion
Grossman, Ralph	Ralph Grossman, Ltd.
Hangebrauck, Robert P.	EPA, Energy Assessment and Control Division
Heck, Ronald	Englehard Industries
Hensel, Thomas E.	Turbo Power and Marine Systems
Holden, Edward A.	General Foods Corporation
Honea, Dr. Franklin I.	Midwest Research Institute
Howard, Jack B.	Massachusetts Institute of Technology
Hudson, Jr., James L.	Tampa Electric Company
Jackson, Dr. A.W.	Ontario Hydro
Jepson, Dr. A.F.	Environmental Measurements, Inc.
Karas, Dennis T.	East Chicago Air Quality Control
Kemmerer, Jeffrey	Fuller Company
Khan, M. Ali	East Chicago Air Quality Control
Khoo, Dr. S.W.	Canadian Gas Research Institute
Kloecker, J.F.	Erie City Energy Division
Kykendal, William	EPA, Process Measurement Branch
Lahre, Thomas	EPA, Office of Air Quality, Planning & Standards
Lange, Dr. Howard	Babcock & Wilcox
Lavoie, Raymond C.	Rohm & Haas Company
Lee, James E.	Facilities Engineering Command (U.S. Navy)
Lenney, Ronald J.	Ronald J. Lenney Associates
Levy, Arthur	Battelle-Columbus Laboratories
Lewis, F. Michael	Stanford Research Institute
Lii, Dr. C.C.	EPA, Combustion Research Branch
Lin, Donald J.L.	Forney Engineering Company
Locklin, David W.	Battelle-Columbus Laboratories
Lord, Harry C.	Environmental Data Corporation
Loweth, Carl	The Trane Company
Marshall, David	Babcock & Wilcox
Marshall, John H.	Combustion Engineering

LIST OF PARTICIPANTS (CONT'D)

Name	Representing
Marton, Miklos B.	IBM
Mayfield, D. Randell	EPA, Region IV
Meier, John G.	International Harvester, Solar Division
Moore, Douglas S.	Chevron Research Company
Moore, Edward E.	Eclipse, Inc.
Morton, William J.	E. Keeler Company
Moscowitz, Charles	Monsanto Research Corporation
Mosier, Stanley A.	Pratt & Whitney
Newton, Charles L.	Colt Industries
Nurick, W.H.	Rockwell International, Rocketdyne Division
Pantzer, Karl	Babcock & Wilcox
Pershing, David W.	University of Arizona
Pertel, Dr. Richard	Institute of Gas Technology
Renner, Ted	Fuel Merchants Association of New Jersey
Riley, Joseph	EPA, Region IV
Robert, J.	Canadian Department of Environment
Roberts, Dr. George	Englehard Industries
Robertson, J.F.	Crystal Petroleum Company
Roffe, Gerald	General Applied Science Laboratories
Rosen, Meyer	Union Carbide
Ross, Marvin	Lawrence Livermore Laboratory
Rulseh, Roy	Cleaver-Brooks
Sadowski, R.S.	Riley Stoker Corporation
Samples, J.R.	Union Carbide
Scott, Donald R.	Columbia Gas System Service Corporation
Sheffield, E.W.	TRW
Slack, A.V.	SAS Corporation
Smith, Lowell L.	KVB, Inc.
Spadaccini, L.J.	United Technology Research Center
Sterman, Sam	Union Carbide
Sullivan, Robert E.	General Motors
Swearingen, W.E.	Koppers Company
Takacs, Dr. L.	General Motors
Taylor, Barry R.	Massachusetts Institute of Technology
Utterback, Paul M.	Babcock & Wilcox
Van Grouw, Sam J.	KVB, Inc.
Vatsky, Joel	Foster-Wheeler Energy Corporation
Vershaw, Jim	The Trane Company
Watson, Raymond A.	Florida Power & Light Company
Webb, R.	The Trane Company
Weiland, J.H.	Texaco, Inc.
Weinberger, Dr. Lawrence	Mitre Corporation
White, David J.	International Harvester, Solar Division
White, James H.	Coen Company
White, Phil	Ventura Company

LIST OF PARTICIPANTS (CONT'D)

Name	Representing
Wiedersum, George C.	Philadelphia Electric Company
Wilhelm, Ronald	Aqua-Chem, Inc.
Wilson, Jr., R.P.	Arthur D. Little, Inc.
Winters, Harry K.	Ray Burner Company
Wittig, Dr. Sigmar L.K.	Purdue University
Woolfolk, Dr. Robert	Stanford Research Institute
Wright, Richard	Industrial Combustion
Young, Dexter E.	EPA, Control Programs Development Division
Ziarkowski, Stanley	Gamlen Chemical Company
Zielke, Robert L.	Tennessee Valley Authority
Zirkel, Eric C.	Armstrong Cork

LIST OF ORGANIZATIONS REPRESENTED

Name (Represented By)	Address
Acurex Corporation, Aerotherm Division (Mr. Anderson)	485 Clyde Avenue Mountain View, California 94042
American Boiler Manufacturers Association (Mr. Axtman)	1500 Wilson Boulevard, Suite 317 Arlington, Virginia 22209
American Gas Association Labs (Mr. De Werth)	8501 East Pleasant Valley Road Cleveland, Ohio 44131
American Petroleum Institute (Mr. Cotton)	1801 K Street, N.W. Washington, D.C. 20006
Apollo Chemical (Dr. Bennett)	35 South Jefferson Road Whippany, New Jersey 07981
Aqua-Chem, Inc. (Mr. Wilhelm)	P.O. Box 421 Milwaukee, Wisconsin 53201
Armstrong Cork Company (Mr. Carpenter, Mr. Zirkel)	Liberty & Charlotte Streets Lancaster, Pennsylvania 17604
Babcock & Wilcox (Mr. Barsin, Mr. Lange, Mr. Moore)	20 South Van Buren Avenue Barberton, Ohio 44203
(Mr. Utterback, Mr. Pantzer, Mr. Marshall)	P.O. Box 2423 North Canton, Ohio 44720
Baltimore Gas and Electric Company (Mr. Alvey)	2012 Gas and Electric Building Baltimore, Maryland 21203
Battelle-Columbus Labs (Mr. Ban, Mr. Barrett, Mr. Levy, Mr. Locklin)	505 King Avenue Columbus, Ohio 43201
C-E Air Preheater (Mr. Clark)	Andover Road Wellsville, New York 14895
California Air Resources Board (Mr. Goodley)	1709 11th Street Sacramento, California 95814
Canadian Department of Environment (Mr. Robert)	351 St. Joseph Boulevard Houll, Quebec, Canada
Canadian Gas Research Institute (Dr. Khoo)	55 Scarsdale Road, Don Mills Ontario, M3B2R3, Canada
Chevron Research Company (Mr. Cleverdon, Mr. D. Moore)	P.O. Box 1627 Richmond, California 94802

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
Cleaver-Brooks (Mr. Rulseh)	3707 North Richards Street Milwaukee, Wisconsin 53201
Coen Company (Mr. J.H. White)	1510 Rollins Road Burlingame, California 94010
Colt Industries (Mr. Newton)	701 Lawton Avenue Beloit, Wisconsin 53511
Columbia Gas System Service Corporation (Mr. Scott)	1600 Dublin Road Columbus, Ohio 43215
Combustion Engineering (Mr. Bueters, Mr. Goetz, Mr. Marshall)	1000 Prospect Hill Road Windsor, Connecticut 06095
Crystal Petroleum Company (Mr. Robertson)	P.O. Box 4180 Corpus Christi, Texas 78408
Drexel University (Dr. Cernansky)	Philadelphia Pennsylvania 19104
EBASCO (Mr. Chu)	145 Technology Park Norcross, Georgia 30071
East Chicago Air Quality Control (Mr. Karas, Mr. Khan)	900 East Chicago Avenue East Chicago, Indiana 45312
Eclipse, Inc. (Mr. E. Moore)	1100 Buchanan Rockford, Illinois 61101
Englehard Industries (Mr. Blandford, Dr. Heck, Dr. Roberts)	Middlesex Turnpike, Wood Avenue Edison, New Jersey 08876
Environmental Data Corporation (Mr. Lord)	608 Fig Avenue Monrovia, California 91016
Environmental Measurements, Inc. (Dr. Jepsen)	2 Lincoln Court Annapolis, Maryland 21401
Environmental Protection Agency EPA - Administrative Office (Mr. Greene)	Research Triangle Park North Carolina 27711

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
EPA - Combustion Research Branch (Dr. Bowen, Mr. Hall, Mr. Lachapelle, Mr. Lanier, Dr. Lii, Mr. Martin, Mr. Wasser)	Research Triangle Park North Carolina 27711
EPA - Control Programs Development Division (Mr. Creekmore, Mr. Young)	Research Triangle Park North Carolina 27711
EPA - Energy Assessment & Control Division (Mr. Hangebrauck)	Research Triangle Park North Carolina 27711
EPA - Office of Air Quality, Planning, and Standards (Mr. Bauman, Mr. Christiano, Mr. Donaldson, Mr. Lahre)	Research Triangle Park North Carolina 27711
EPA - Office of Research and Development (Mr. Graham)	Washington, D.C. 20460
EPA - Process Measurement Branch (Mr. Kuykendal)	Research Triangle Park North Carolina 27711
EPA - Region IV (Mr. Biggs, Mr. Mayfield, Mr. Riley)	1421 Peachtree Street, N.E. Atlanta, Georgia 30309
Erie City Energy Division (Mr. Fuhrman, Mr. Kloecher)	1422 East Avenue Erie, Pennsylvania 16502
Exxon Research & Engineering Company (Mr. Bartok)	P.O. Box 8 Linden, New Jersey 07036
Federal Energy Administration (Mr. Freelain)	1200 Pennsylvania Avenue, N.W. Washington, D.C. 20461
Florida Power & Light Company (Mr. Watson)	P.O. Box 013100 Miami, Florida 33101
Forney Engineering Company (Mr. Lin)	P.O. Box 189 Addison, Texas 75001
Foster Wheeler Energy Corporation (Mr. Vatsky)	10 South Orange Avenue Livingston, New Jersey 07039
Fuel Merchants Association of New Jersey (Mr. Renner)	66 Morris Avenue Springfield, New Jersey 07081

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
Fuller Company (Mr. Kemmerer)	124 Bridge Street Catasauqua, Pennsylvania 18032
GCA/Technology Division (Dr. Fennelly)	Burlington Road Bedford, Massachusetts 01730
Gamlen Chemical Company (Mr. Downey, Mr. Ziarkowski)	299 Market Street Saddle Brook, New Jersey 07662
General Applied Science Laboratories (Mr. Roffe)	Merrick & Stewart Avenues Westbury, New York 11790
General Foods - Technical Center (Mr. Holden)	250 North Street White Plains, New York 10625
General Motors Corporation (Mr. Sullivan)	5735 West 25th Street Indianapolis, Indiana 46224
(Mr. Dingo, Mr. Takacs)	Technical Center Warren, Michigan 48090
Gulf Research and Development Company (Mr. Dzuna)	P.O. Box 2038 Pittsburgh, Pennsylvania 15230
Honeywell, Inc. (Mr. Bonne)	Bloomington Minnesota 55420
IBM (Mr. Marton)	1000 Westchester Avenue White Plains, New York 10604
Industrial Combustion (Mr. Wright, Mr. Fletcher)	4465 North Oakland Milwaukee, Wisconsin 53211
Institute of Gas Technology (Dr. Pertel)	3424 South State Street Chicago, Illinois 60616
International Boiler Works (Mr. Blythe)	P.O. Box 498 East Stroudsburg, Pennsylvania 18301
International Harvester, Solar Division (Mr. Meier, Mr. D.G. White)	2200 Pacific Highway San Diego, California 92119

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
KVB Engineering, Inc. (Mr. L. Smith, Mr. Van Grouw)	6624 Hornwood Drive Houston, Texas 77036
E. Keeler Company (Mr. Morton)	Williamsport Pennsylvania 17701
Koppers Company, Inc. (Mr. Swearingen)	Koppers Building Pittsburgh, Pennsylvania 15219
Ronald J. Lenney Associates (Mr. Lenney)	2001 Palmer Avenue Larchmont, New York 10538
Arthur D. Little, Inc. (Mr. R.D. Wilson)	Acorn Park Cambridge, Massachusetts 02140
Lawrence Livermore Laboratories (Mr. Bowman, Mr. Ross)	P.O. Box 808 Livermore, California 94550
Massachusetts Institute of Technology (Mr. Howard, Mr. Taylor)	Massachusetts Avenue Cambridge, Massachusetts 02139
Midwest Research Institute (Dr. Honea)	425 Volker Boulevard Kansas City, Missouri 64110
Mitre Corporation (Dr. Weinberger, Mr. Erskine)	Westgate Research Park 1820 Dolly Madison Boulevard McLean, Virginia 22101
Monsanto Research Corporation (Mr. Moscowitz)	Station B. Box 8 Dayton, Ohio 45407
NOFI (Mr. Beals)	New York, New York
Naval Facilities Engineering Command, Southern Division (Mr. J. Lee)	2144 Melbourne Street P.O. Box 10068 Charleston, South Carolina 29411
New England Electric Systems (Mr. Batra)	20 Turnpike Road Weston, Massachusetts 01581
Northern Research & Engineering Corporation (Mr. Demetri)	219 Vassar Street Cambridge, Massachusetts 02139

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
Ontario Hydro Corporation (Mr. Booth, Dr. Jackson)	620 Union Avenue Toronto, Ontario, Canada M561X6
Peabody Engineering Corporation (Mr. R. Fletcher)	835 Hope Street Stamford, Connecticut 06907
Philadelphia Electric Company (Mr. Wiedersom)	2301 Market Street, S10-1 Philadelphia, Pennsylvania 19101
Pratt & Whitney Aircraft (Mr. Daughtridge, Mr. Mosier)	P.O. Box 2691 West Palm Beach, Florida 33402
Process Combustion Corporation (Mr. Grimshaw)	1675 Washington Road Pittsburgh, Pennsylvania 15228
Procter & Gamble Company (Mr. Beatty)	610 South Center Hill Road Cincinnati, Ohio 45224
Purdue University (Mr. Wittig)	West Lafayette Indiana 47907
Ralph Grossman, Ltd. (Mr. Grossman)	P.O. Box 70, Town of Mt. Royal Montreal, Canada H3P 3B8
Ray Burner Company (Mr. Winters)	1301 San Jose Avenue San Francisco, California 94112
Research-Cottrell, Inc. (Dr. Frisch)	P.O. Box 750 Boundbrook, New Jersey 08805
Riley Stoker Corporation (Mr. Sadowski)	9 Neponset Street Worcester, Massachusetts 01613
Rockwell International Corporation, Rocketdyne Division (Mr. Nurick)	6633 Canoga Avenue Canoga Park, California 91304
Rohm & Haas Company (Mr. Lavoie)	P.O. Box 584 Bristol, Pennsylvania 19007
SAS Corporation (Mr. Slack)	RFD #1 Sheffield, Alabama 35660

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
Sandia Laboratories (Mr. Dyer)	Livermore California 94550
Selas Corporation of America (Mr. Feng)	Dresher Pennsylvania 19025
Shell Development Company (Mr. Dygert, Mr. Baker)	P.O. Box 481 Houston, Texas 77001
South California Edison (Mr. Bagwell)	P.O. Box 800 Rosemead, California 91770
Stanford Research Institute (Dr. Woolfolk, Mr. Lewis)	1611 North Kent Street Arlington, Virginia 22209
Systems Research Labs (Mr. Buechler, Mr. Degler)	2800 Indian Ripple Road Dayton, Ohio 45440
TRW, Inc. (Mr. Sheffield)	1 Space Park - R4/2000 Redondo Beach, California 90278
Tampa Electric Company (Mr. Hudson)	P.O. Box 111 Tampa, Florida 33601
Tennessee Valley Authority (Mr. Zielke)	524 Power Building Chattanooga, Tennessee 37401
Texaco, Inc. (Mr. Weiland)	P.O. Box 509 Beacon, New York 12508
The Trane Company (Mr. Loweth, Mr. Vershaw, Mr. Webb)	3600 Pammel Creek Road La Crosse, Wisconsin 54601
Turbo Power and Marine Systems (Mr. Hensel)	1690 New Britain Avenue Farmington, Connecticut 06032
Union Carbide Corporation (Mr. Rosen, Mr. Sterman)	Tarrytown Technical Center Tarrytown, New York 10591
(Mr. Dowling)	Box 180 Sistersville, West Virginia 26175

LIST OF ORGANIZATIONS (CONT'D)

Name (Represented By)	Address
Union Carbide Corporation (Mr. Samples)	Box 4361 South Charleston, West Virginia 25353
United Technologies Research Center (Mr. Spadaccini)	400 Main Street East Hartford, Connecticut 06040
University of Arizona (Mr. Pershing)	Tucson Arizona 85721
Ventura County A.P.C.D. (Mr. P. White)	740 East Main Street Ventura, California 93001

*U.S. GOVERNMENT PRINTING OFFICE: 1976-641-317/5513 Region No. 4